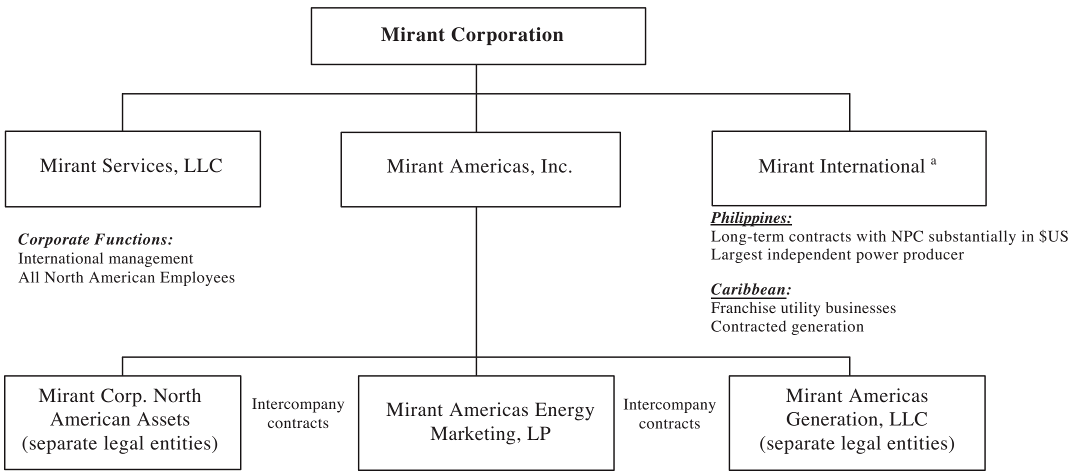
V.

GENERAL INFORMATION

The Debtors consist of Mirant and most of its direct and indirect U.S. subsidiaries. The chart below depicts the corporate structure of Mirant and its principal subsidiaries as of the date of the Disclosure Statement.[1] The description in "General Information" of Mirant, its subsidiaries and their respective businesses, does not give effect to any changes in the corporate structure of the Debtors in connection with or under the Plan.



Mirant Corp. Asset Ownership:[b]

Potomac River (VA)	West Georgia (GA)
Peaker (MD)	Apex (NV)
Zeeland (MI)	Wichita Falls (TX)[c]
Sugar Creek (IN)	
Shady Hills (FL)	

Commercial Operation of Assets:

Plant Dispatch
Fuel Procurement
Bidding
Delivery of Fuel and Power
Hedging — Physical and Financial
Longer-term Marketing Deals
Asset Optimization

MAG Facilities:

MID-ATLANTIC	NEW ENGLAND
Morgantown	Kendall
Dickerson	Canal
Chalk Point	CALIFORNIA
NEW YORK	Delta
Bowline	Pittsburgh
Lovett	Contra Costa
NY-Gen	Potrero
	TEXAS
	Bosque

[a] None of Mirant's non-U.S. subsidiaries have filed chapter 11 petitions.

[b] Represents Mirant's domestic power Assets, excluding Assets owned directly or indirectly by MAG.

[c] See "The Chapter 11 Cases — Material Asset Sales" for information on the sale of this facility.

A. The Businesses of Mirant

As of December 31, 2004, Mirant, through its direct or indirect subsidiaries, owned or leased approximately 18,000 megawatts ("MW") of electric generating capacity. Mirant manages its business through two principal operating segments: North America and International. The North America segment consists of the ownership and operation of power generation facilities, including those owned by MAG and MIRMA, and energy trading and marketing operations, principally conducted through MAEM. Mirant's International segment includes power generation businesses in the Philippines, Curacao, Trinidad and Tobago, and integrated utilities in the Bahamas and Jamaica.

[1] A comprehensive Group Structure Chart is attached as Schedule 3.

1. The North American Business

The power industry is one of the largest industries in the United States and has an influence on practically every aspect of the U.S. economy. Historically, the power generation industry in the United States was characterized by electric utility monopolies selling to franchised customer bases. In response to increasing customer demand for access to low-cost electricity and enhanced services, regulatory initiatives were adopted, primarily to increase wholesale and retail competition in the power industry. Following the resulting industry restructuring, merchant companies purchased plants from regulated utilities, built new capacity and began marketing to customers. At the same time, ISOs and/or RTOs were created to administer the new markets while maintaining system reliability. In recent years, state and federal restructuring efforts have stalled, primarily in response to the California energy crisis and financial troubles of many merchant energy companies. In addition, ISOs have begun exerting more control over market prices. The result is a blend of competitive and regulatory constructs, often different by state, under which merchant generators generally must compete with each other and, in some states, with regulated utilities.

In the United States, the Debtors serve four primary geographic areas: (a) the Mid-Atlantic region, (b) the Northeast region, (c) the Mid-Continent region, and (d) the West region. The core business of the Debtors centers on the production and sale of electrical energy, electrical capacity (essentially the ability to produce electricity on demand) and ancillary services. The Debtors' customers in the United States are utilities, municipal systems, aggregators, electric-cooperative utilities, producers, generators, marketers and large industrial customers.

a. Ownership and Operation of Electricity Generation Assets

Through Mirant, MAI and MAI's wholly owned direct and indirect subsidiaries, MAEM, MAG and MIRMA, the Debtors own or lease generation facilities in the United States with an aggregate generation capacity of 14,500 MW (including the Wrightsville facility, the sale of which was approved by the Bankruptcy Court on June 1, 2005, and including Wichita Falls, which is to be sold as described further in "The Chapter 11 Cases — Material Asset Sales"). MAG owns or controls indirectly over two-thirds of the Debtors' North American generating capacity. The domestic generating portfolio of the Debtors is diversified across fuel types, power markets and dispatch types, and serves customers located near many major metropolitan load centers. The following North America properties were owned or leased by the Debtors as of September 1, 2005:

Power Generation Business	Location	Plant Type	Primary Fuel	Mirant's % Leasehold/ Ownership Interest	Total MW	Net Equity Interest/ Lease in Total MW
NORTH AMERICA						
West Region:						
Mirant California[a]	California	Peaking/Intermediate	Natural Gas	100	2,347	2,347
Apex	Nevada	Intermediate	Natural Gas	100	500	500
Mirant Wichita Falls[b]	Texas	Peaking	Natural Gas	100	77	77
Mirant Texas	Texas	Peaking/Baseload	Natural Gas	100	538	538
Subtotal					3,462	3,462

[a] See "Regional Markets — West Region" for details on the impending retirement of Pittsburg Unit 7.

[b] See "The Chapter 11 Cases — Material Asset Sales" for details on the sale of the Mirant Wichita Falls facility.

Power Generation Business	Location	Plant Type	Primary Fuel	Mirant's % Leasehold/ Ownership Interest	Total MW	Net Equity Interest/ Lease in Total MW
Northeast Region:						
Mirant New York	New York	Intermediate/Peaking/ Baseload	Natural Gas/ Hydro/Coal/ Oil	100	1,675	1,675
Mirant New England[a] ...	Massachusetts	Intermediate/Peaking	Natural Gas/Oil	100	1,993	1,388
Subtotal.............					3,668	3,063
Mid-Atlantic Region:						
Mirant Peaker and Mirant Potomac River	Maryland/Virginia	Intermediate/Peaking/ Baseload	Natural Gas/ Coal/Oil	100	1,004	1,004
Mirant Mid-Atlantic	Maryland	Intermediate/Peaking/ Baseload	Natural Gas/ Coal/Oil	100	4,252	4,252
Subtotal.............					5,256	5,256
Mid-Continent Region:						
Mirant Zeeland	Michigan	Peaking/Intermediate	Natural Gas	100	837	837
Sugar Creek	Indiana	Peaking	Natural Gas	100	535	535
West Georgia	Georgia	Peaking	Natural Gas/ Oil	100	605	605
Shady Hills	Florida	Peaking	Natural Gas	100	468	468
Subtotal.............					2,445	2,445
North America Total ...					15,831	14,226

[a] Mirant's ownership interest in the facilities in this region is 100%, except for the 614 MW Wyman plant in which Mirant has a 1.4% ownership interest, or 8.8 MW. See "Regional Markets — Northeast Region — New England" for details regarding current plans to mothball the Mirant Kendall facility.

b. Commercial Operations

The Debtors conduct their commercial activities through MAEM. These activities consist of fuel procurement, power dispatch, logistics, asset hedging and risk management, and optimization trading. MAEM conducts its business in the markets in which the Debtors have an asset presence. This asset presence enhances the ability of MAEM to manage risk and deliver additional value as compared to only buying fuel and selling power in the spot market.

Pursuant to agreements with the Debtors that own generation facilities, MAEM enters into transactions for the benefit of such Debtors pursuant to which MAEM procures the appropriate fuel, formulates the daily dispatch decisions and sells the electricity generated in the wholesale market for the generation facilities. MAEM uses dispatch models to make daily decisions regarding the quantity and the price of the power it will sell into the markets. In markets governed by ISOs/RTOs, MAEM bids the energy from the Debtors' generation facilities into the ISO-run day-ahead and spot energy markets. MAEM also sells ancillary services through the ISO markets. In real-time, MAEM works with the ISOs/RTOs to ensure the generation facilities of the Debtors are dispatched economically to meet the reliability needs of the market. In non-ISO markets, MAEM conducts business through bilateral transactions pursuant to which MAEM provides dispatch schedules to the generation facilities.

MAEM enters into contracts of varying terms to secure appropriate quantities of fuel that meet the varying specifications of the Debtors' generating facilities. For the Debtors' coal fired generation facilities, MAEM purchases coal from a variety of suppliers under both short-term and multi-year contracts. For the Debtors' oil fired units, fuel is typically purchased under short-term contracts usually linked to a transparent

oil index price. For the Debtors' gas fired units, MAEM typically purchases natural gas under short-term contracts with a variety of suppliers on a day-ahead or monthly basis.

MAEM enters into transactions to economically hedge the power price and fuel and emissions cost exposure of the Debtors by selling power into the wholesale market or buying fuel and emissions over a variety of tenors through over-the-counter transactions, exchanges and structured transactions. MAEM buys and sells both energy and energy-linked commodities, including capacity and ancillary services. MAEM economically hedges the energy component of gross margin through futures, forwards, swaps and options. All of MAEM's commercial activities are governed by the Debtors' Risk Management Policy ("RMP"). The RMP requires that MAEM engage only in risk reducing activities with respect to hedging the Debtors' Assets.

While over-the-counter transactions make up a substantial portion of the Debtors' economic hedge portfolio, MAEM also has a marketing function that serves as the interface between the Debtors' generation facilities and customers. The marketing organization is focused on selling non-standard, structured products to customers. In addition to energy, these products typically include capacity, ancillary services, and other energy products. MAEM views these transactions as a method of mitigating the risk of certain portions of the Debtors' business that are not easy to economically hedge in the over-the-counter market. Typically, MAEM is able to sell these products at a higher premium than standard products. For certain generation facilities, MAEM has sought to enter into longer-term transactions to provide certainty of cash flows over an extended period. These transactions are typically tolling transactions whereby a Debtor receives a fixed capacity payment and, in return, grants an exclusive right for the counterparty to procure the fuel for the generation facility and take title to the power generated.

In addition to the risk management services that MAEM provides to the Debtors that own generation facilities, MAEM engages in optimization trading for its own account. MAEM generates gross margin by taking market positions based, in part, on market and other information gathered from its relationship with the Debtors' generation facilities and its fuel and emissions purchasing activities. The optimization trading activities also are governed by the RMP, which sets forth limits on the size of trading positions and value-at-risk that MAEM can bear at any given time. By participating in the markets in this way, MAEM is better able to avoid disclosing to the markets the direction of its trading and hedging activity, to the benefit of the Debtors that own generation facilities. The Debtors that own generation facilities also benefit from tighter bid/offer spreads because MAEM is active in the markets as both a buyer and a seller.

c. Regional Markets

i. Mid-Atlantic Region[1]

Mirant owns (directly and indirectly) or leases four generation facilities comprising 5,256 MW of generation capacity in the Mid-Atlantic region: Chalk Point, Morgantown, Dickerson and Potomac River Station. These Mid-Atlantic facilities were acquired from Pepco in December 2000. These facilities consist of coal and oil fired baseload units as well as coal, gas and oil fired intermediate and peaking units in Maryland and Virginia. Mid-Atlantic's largest facility in the region, the Chalk Point facility, has two coal fired baseload units, two oil and gas fired intermediate units and seven either oil fired or oil and gas fired peaking units totaling 2,429 MW of capacity. The next largest facility, the Morgantown facility, consists of two coal and oil fired baseload units and six oil fired peaking units, totaling 1,492 MW of capacity. The Dickerson facility has three coal fired baseload units and three peaking units, totaling 853 MW of capacity, and the Potomac River Station, a coal fired facility, has three baseload and two intermediate units, totaling 482 MW of capacity.

Power generated by Mirant's facilities in the Mid-Atlantic region is sold into the PJM market. In connection with the acquisition of the Mid-Atlantic facilities from Pepco in 2000, Mirant, through MAEM, agreed to supply Pepco its full load requirement in the District of Columbia under a TPA, which expired in January 2005 (the "DC TPA"). MAEM also had a similar TPA in place to supply Pepco's load in Maryland,

[1] Potomac Electric Power Company ("Pepco") and Southern Maryland Electric Cooperative, Inc. ("SMECO") have requested modifications to the following section that the Debtors find objectionable. For the full text of Pepco's and SMECO's proposed alternative language, see Exhibit E.

which expired in June 2004 (the "Maryland TPA"). On October 29, 2003, the Debtors filed a motion with the Bankruptcy Court for approval of a settlement ("Pepco TPA Settlement") between the Debtors and Pepco regarding the TPAs, which were out-of-market. Under the Pepco TPA Settlement, the per megawatt hour ("MWh") prices for power delivered under the TPAs were increased by $6.40 and the TPAs were assumed. In addition, the Pepco TPA Settlement grants Pepco an allowed prepetition general Unsecured Claim against Mirant and MAEM related to the amendment of these agreements in the amount of $105,000,000. On November 19, 2003, the Bankruptcy Court approved the Pepco TPA Settlement and the assumption of the amended TPAs.[1]

Also, in connection with the Debtors' acquisition of the Mid-Atlantic facilities from Pepco in 2000, Mirant and Pepco entered into a contractual agreement (the "Back-to-Back Agreement") with respect to certain long-term PPAs, including PPAs with Ohio Edison and Panda, under which: (A) Pepco agreed to resell to Mirant all "capacity, energy, ancillary services and other benefits" to which it is entitled under those agreements and (B) Mirant agreed to pay Pepco each month all amounts due from Pepco to the sellers under those PPAs for the immediately preceding month associated with such capacity, energy, ancillary services and other benefits. The Panda and Ohio Edison PPAs run until 2021 and December 31, 2005, respectively. Under the Back-to-Back Agreement, Mirant is obligated to purchase power from Pepco at prices that are significantly higher than existing market prices for power in the PJM market. Since August 2003, the Debtors have sought to reject the Back-to-Back Agreement. For more details concerning the current status of the Debtors' efforts to reject the Back-to-Back Agreement, see "Material Claims, Litigation and Investigations — Disputed Claims with Associated Estate Causes of Action — Pepco Litigation." Furthermore, the Debtors have commenced a fraudulent transfer action against Pepco regarding the original acquisition. See "Material Claims, Litigation and Investigations — Other Estate Claims — Avoidance Actions."[1]

Since the expiration of the Maryland TPA in June 2004 and the DC TPA in January 2005, MAEM has been hedging the output of the Mid-Atlantic generation facilities in the bilateral market as described in "General Information — The Businesses of Mirant — The North American Business." The terms for these transactions extend into 2006. In addition, MAEM enters into structured transactions with entities serving load in the greater Washington, D.C. area. Structured transactions are inherently more complicated than bilateral transactions, and MAEM looks to extract value over the mid-point of the market for such deals. The terms for these transactions extend into 2006 as well.

MAEM has also participated in standard offer service auctions in Maryland and Washington, D.C. Power sales, made either directly through these auctions or indirectly through subsequent market transactions that are a result of the auction process, serve as economic hedges for the Mid-Atlantic Assets.

ii. Northeast Region

The Debtors own or operate generating facilities in the Northeast region consisting of approximately 3,063 MW of capacity. The Northeast region is comprised of the New York and New England sub-regions. Generation is sold from the Debtors' Northeast Assets through a combination of bilateral contracts, spot market transactions, and structured transactions.

(A) New York

The Debtors' New York facilities were acquired from Orange and Rockland Utilities, Inc. and Consolidated Edison Company of New York, Inc. in June 1999. The New York generating facilities comprise a total of 1,675 MW of capacity, consisting of the Bowline and Lovett facilities and various smaller generating facilities. The Bowline facility is a 1,133 MW dual fueled (natural gas and oil) facility comprised of two intermediate units. The Mirant Lovett facility consists of two baseload units capable of burning coal and gas comprising a total of 348 MW and a peaking unit capable of burning gas or oil comprising 63 MW. The smaller Mirant New York plant operations, "comprising a total of 132 MW," include two peaking units (the Hillburn gas turbine station and the Shoemaker gas turbine station), three hydroelectric stations (Mongaup

---

[1] Pepco requested modifications to this section that the Debtors find objectionable. For the full text of Pepco's proposed alternative language, see Exhibit E.

1-4, Swinging Bridge 1-2 and Rio 1-2) and an operational interest in the Grahamsville Hydroelectric Station pursuant to a sublease between Orange and Rockland Utilities, Inc. and Mirant NY-Gen, LLC that is set to expire on December 30, 2005. A proposed expansion at the Bowline facility, a 750 MW natural gas and distillate oil fired combined cycle unit, is currently suspended.

The Mirant New York plants participate in a market operated by the NYISO. Market fundamentals in the NYISO do not permit the Debtors to operate the Lovett facility on an economic basis as a merchant generation facility because of upcoming required environmental capital expenditures and property taxes associated with the facility. The current plan of the Debtors is to retire the Mirant Lovett facility starting with Unit 5 in 2007 and Units 3 and 4 in 2008. While the Debtors are pursuing a number of options to lower the property taxes at Lovett, including settlement discussions with the appropriate local governments, the current view of the Debtors is that even with property tax relief, operation of the Lovett facility will not be economical because of the required capital expenditures. While the Debtors are actively exploring alternatives to a shutdown, the current plan of the Debtors does not anticipate Lovett operating past 2008.

(B) New England

The Mirant New England generating facilities, with a total capacity of 1,388 MW, were acquired from subsidiaries of Commonwealth Energy System and Eastern Utilities Associates in December 1998. The New England generating facilities consist of the Kendall station, the Canal station, the Martha's Vineyard diesels and the Wyman Unit 4 interest. The Canal and Kendall facilities, consisting of approximately 1,109 MW and 256 MW of generating capacity, respectively, are designed to operate during periods of intermediate and peak demand, and are located in close proximity to Boston. The Kendall facility has been repowered since its acquisition and is now a natural gas combined cycle facility capable of producing both steam and electricity for sale. Both the Canal and Kendall facilities possess the ability to burn both natural gas and fuel oil. The Martha's Vineyard diesels, with 14 MW of capacity, supply electricity on the island of Martha's Vineyard during periods of high demand or in the event of a transmission interruption. The Wyman Unit 4 interest is an approximate 1.4% ownership interest (equivalent to 8.8 MW) in the 614 MW Wyman Unit 4 located on Cousin's Island, Yarmouth, Maine. It is primarily owned and operated by the Florida Power and Light Group.

The capacity, energy and ancillary services from the Mirant New England generating units are sold into the electricity markets administered by the ISO of New England ("ISO-NE"). Current market fundamentals in New England do not permit the Debtors to operate the Kendall facility on an economical basis as a merchant facility. The current plan of the Debtors is to shutdown, at least temporarily, the Kendall facility from January 2006 through December 2007, with the possibility of restarting operations as early as January 2008, if market conditions do not improve. However, the ISO-NE has determined that, based on a localized need by NSTAR Electric Company ("NSTAR"), a small part of the capacity of the Kendall facility, namely steam units 1 and 2 and jet unit 1 (collectively, the "Reliability Units"), is needed, on a temporary basis, for reliability. As a result, the Debtors negotiated a reliability-must-run ("RMR") agreement with the ISO-NE for the continued operation of the Reliability Units.

On October 7, 2004, the Debtors filed the RMR agreement with the FERC. On November 26, 2004, FERC issued an order accepting and suspending the filed RMR agreement to become effective October 8, 2004, subject to refund. Additionally, FERC accepted the proposed RMR rates for filing, suspended them for a nominal period, subject to refund, set the proposed rates for hearing and held the hearing in abeyance so that NSTAR and the Debtors could engage in settlement discussions. NSTAR and the Debtors subsequently entered into a settlement agreement that, once filed and approved by FERC, will resolve all issues in the RMR case. This agreement is effective until 120 days following written notice provided to the Debtors. The Debtors plan to mothball the Kendall facility following the expiration of the RMR agreement if it is not economically feasible to continue to operate the facility.

iii. Mid-Continent Region

The Mirant Mid-Continent facilities, consisting of an equity interest in roughly 2,668 MW, are located in the Midwest and Southeast markets.

(A) Midwest

The Debtors' facilities in the Midwest, which include Sugar Creek and Zeeland, consist of over 1,372 MW of generating capacity and are all natural gas fired peaking and/or intermediate units.

The Sugar Creek facility is a combined cycle facility with the capability to produce 535 MW. Located in West Terre Haute, Indiana, the Sugar Creek facility has the physical capability to be interconnected with either the Cinergy or AEP systems. Cinergy is a member of the MISO and AEP is a member of PJM. The facility is eligible to participate in the energy, capacity and ancillary markets of PJM and MISO. When not covered by a variety of short-term agreements, the facility sells energy into either PJM or MISO (whichever is the best available market). When the unit runs in PJM, it receives a price comparable to the AEP/Dayton Hub.

The Zeeland facility, located in Zeeland, Michigan, is comprised of simple cycle units totaling 307 MW of capacity and a 530 MW combined cycle facility (837 MW of total capacity). The Zeeland facility is interconnected with the International Transmission Company, which is a member of the MISO.

Mirant Zeeland has a five-year tolling agreement with MAEM for the electrical energy output (306 MW, simple cycle) from the Zeeland plant, Phase I Units 1A and 1B. MAEM has a counterparty agreement to sell simple cycle capacity output from Mirant Zeeland Units 1A and 1B through May 31, 2006. Mirant Zeeland receives from MAEM, and MAEM receives from its counterparty, a monthly capacity payment, a variable operating and maintenance payment on a per MWh basis and a start-up payment. The counterparty provides to Mirant Zeeland, through MAEM, all the fuel required to operate the contractual portion of the plant. Mirant Zeeland indirectly provides a heat rate and availability guarantee. There are bonus and penalty provisions in the agreement for availability outside allowable limits. Mirant Zeeland Phase 2 (530 MW combined cycle output) has a tolling contract for 100% of the output through February 2006. As with Phase 1, the toll is with MAEM who in turn has an agreement with a counterparty. Mirant Zeeland receives from MAEM, and MAEM receives from its counterparty, a monthly capacity payment, variable operations and maintenance payments on a per MWh basis and a start charge. As with the Phase 1 toll, there are heat rate and availability guarantees with associated bonuses and penalties for being outside of tolerance bands. The fuel required to operate the facility during the term of the toll is provided to Mirant Zeeland through the MAEM agreement with its counterparty. Both the Zeeland and Sugar Creek facilities operate under the East Central Area Reliability Coordination Agreement ("ECAR") market.

(B) Southeast

The Debtors have three facilities in the Southeast with a net equity interest of 1,296 MW. The West Georgia facility in Thomaston, Georgia and the Shady Hills facility in Pasco County, Florida consist of gas and oil fired combustion turbines serving peak loads of approximately 605 MW and 468 MW, respectively. Additionally, the Debtors developed, in partnership with Kinder Morgan Power Company, the Wrightsville facility in Wrightsville, Arkansas, which consists of gas fired intermediate/peaking units with generating capacity of 438 MW. The Wrightsville facility was jointly owned with Kinder Morgan Power Company, and MAI held a $180,000,000 senior unsecured loan to the special purpose entity that held a senior secured interest in the Wrightsville facility. In 2004, the Debtors mothballed this facility, pending regional recovery of power prices. In February 2005, the Debtors entered into an agreement to sell the Wrightsville facility to AECC, subject to Bankruptcy Court approval and certain other regulatory and third-party consents and approvals. On September 28, 2005, the sale of the Wrightsville facility to AECC was consummated.

West Georgia has a PPA for the output of the West Georgia facility that will expire in May 2009. The annual capacity amount nominated by West Georgia is currently approximately 450 MW. West Georgia receives a capacity payment, start-up payments, and variable operating and maintenance payments on a per MWh basis and an index-based fuel payment. The PPA allows West Georgia to provide replacement energy from the market to meet contractual obligations. West Georgia may receive bonuses or incur penalties for availability outside allowable limits. There are no provisions for renewal or extension of the contract.

West Georgia has a fuel supply contract, which expires in May 2009. West Georgia has also purchased firm gas transportation for 22,500 MMbtu/day for the months June through September under an agreement that expires in May 2009.

On September 22, 2005, El Paso Marketing, L.P. provided verbal notice to West Georgia Generating Company, L.L.C. of a force majeure event commencing on September 22, 2005 due to Hurricane Rita as it relates to the firm natural gas contract between EPM and WGGC. El Paso confirmed the force majeure event in writing to WGGC on September 27, 2005. WGGC provided notice to Georgia Power Company on September 22, 2005 and again on September 27, 2005 of the Hurricane Rita force majeure event commencing on September 22, 2005 under the PPA between GPC and WGGC.

Shady Hills has a third party tolling agreement through March 2007 for the output of its 468 MW facility. The counterparty tolls 100% of the output of the facility, and the annual capacity amount is determined by a performance test conducted each spring. Shady Hills receives a monthly capacity payment, a variable operating and maintenance payment on a per MWh basis, and a start-up payment each time a unit is turned on. The counterparty schedules and delivers all fuel. Shady Hills generates electricity and provides a heat rate guarantee and receives bonuses and pays penalties outside the guarantee values. Shady Hills is required to meet minimum availability requirements and may incur penalties for availability outside allowable limits. The counterparty has a right of first refusal on the output of any expansion at the site during the contract term. There are no renewal provisions in the agreement.

Once the existing tolling agreement expires, another tolling arrangement will begin. Under this agreement, which was executed in August 2004, 100% of the Shady Hills power facility will be tolled from April 2007 to April 2014. The general terms of this tolling agreement are similar to the first arrangement, except there is no right of first refusal granted to the counterparty related to expansion at the facility.

iv. West Region

The Debtors' West region facilities consist of a net equity interest in 3,462 MW of gas fired generating capacity in California, Nevada and Texas.

(A) California

In April 1999, Mirant California, through its wholly owned subsidiaries, Mirant Delta and Mirant Potrero, acquired various generating assets in California with a total capacity of 2,948 MW from PG&E. As of December 31, 2004, the Debtors had retired around 600 MW of that total capacity. The assets acquired consist of the Pittsburg plant and the Contra Costa plant (the "Delta Plants") owned by Mirant Delta and the Potrero plant owned by Mirant Potrero. These generating assets, which include facilities operating at both intermediate and peak demand levels, are located in, or in close proximity to, San Francisco. The Delta Plants consist of five intermediate natural gas fired steam generating units with approximately 1,985 MW of generating capacity located approximately ten miles apart along the Sacramento/San Joaquin river delta. The Potrero plant has one baseload natural gas fired conventional steam generating unit and three peaking distillate fueled combustion turbines with a combined capacity of 362 MW.

The majority of the Debtors' Assets in California are subject to RMR agreements with the CAISO. The Mirant California subsidiaries currently have the largest portfolio of units that operate under RMR agreements, reflecting that the location of these units is key to system reliability. Contra Costa Unit 6 is not a party to an RMR agreement and, thus, functions solely as a merchant facility in the CAISO. MAEM sells the output of Contra Costa Unit 6 into the market through bilateral transactions with utilities and other merchant energy companies.

In October 2004, the CAISO notified the Debtors that the RMR agreement for Pittsburg Unit 7 would not be renewed for 2005. The Debtors have entered into tolling agreements with a third party through the end of 2005 for Pittsburg Unit 7. At the expiration of this agreement, the Debtors plan to retire Pittsburg Unit 7, consisting of 682 MW, in January 2006. The Debtors are currently in the process of soliciting bids for tolling agreements for Contra Costa Unit 6 and Pittsburg Unit 7.

In September 2005, the CAISO Board approved RMR designations for 2006 that are the same as designations for 2005. The CAISO has not formally notified the Debtor of these RMR elections. Formal notification is expected on or before October 1, 2005.

As part of the California Settlement, PG&E entered into two power purchase agreements with Mirant Delta and Mirant Potrero that will allow PG&E to dispatch and purchase the power output of all units of the generating plants owned by those entities that have been designated by the CAISO as RMR units under the RMR agreements. For more information concerning these agreements, see "The Chapter 11 Plan — Settlements and Compromises — California Settlement."

(B) Nevada

The Apex generating facility, a 500 MW intermediate gas combined-cycle facility located near Las Vegas, Nevada, was developed by Mirant and began commercial operations in May 2003. MAEM has signed contracts with a third party for 225 MW of capacity and energy from the Apex facility for the period from May 2003 to April 2008. In October 2004, MAEM and a third party reached agreement on additional power sales out of the Apex facility. MAEM agreed to sell a market-based heat rate call option representing 175 MW of the Apex facility from June 2005 through September 2005.

(C) Texas

The Debtors operate two facilities in Texas, the Bosque facility and the Wichita Falls facility. The Bosque facility consists of a gas fired combustion turbine with a corresponding steam turbine (combined cycle unit) with a capacity of 230 MW that is available to serve baseload and intermediate. In addition, Bosque Units 1 and 2 are gas-fired peakers with a capacity of 154 MW each. The Wichita Falls facility is a combined cycle facility and consists of three gas turbines and a steam turbine with a total capacity of 77 MW. The Wichita Falls facility primarily sells its electrical output to the merchant market. The Debtors are currently in the process of soliciting bids for a potential sale of the Wichita Falls facility.

In August 2004, Mirant Texas, LP commenced a tolling agreement pursuant to which the counterparty has exclusive rights to the power and ancillary services generated by the Bosque facility through December 2006. Mirant Texas guarantees certain availability requirements to the counterparty and may receive a bonus for availability above the guaranteed level and may incur penalties for availability below allowable limits. The counterparty is responsible for procuring all fuel and for selling the power to retail customers and into the Texas wholesale power market.

Both the Bosque and Wichita Falls facilities operate in the ERCOT market.

d. Regulatory Environment

i. U.S. Public Utility Regulation

The U.S. electricity industry is subject to comprehensive regulation at the federal, state, and local levels. At the federal level, FERC has exclusive jurisdiction under the Federal Power Act over sales of electricity at wholesale and the transmission of electricity in interstate commerce. The Debtors that own generating facilities selling at wholesale or that sell electricity at wholesale outside of ERCOT are "public utilities" subject to FERC's jurisdiction under the Federal Power Act. These Debtors must comply with certain FERC reporting requirements and FERC-approved market rules and are subject to FERC oversight of mergers and acquisitions, the disposition of FERC-jurisdictional facilities, and the issuance of securities (for which blanket authority has been granted). In addition, under the Natural Gas Act, FERC has limited jurisdiction over certain sales for resale of natural gas, but does not regulate the prices received by the Debtors that market natural gas.

FERC has authorized the public utility Debtors to sell energy and capacity at wholesale market-based rates and has authorized some of the public utility Debtors to sell certain ancillary services at wholesale market-based rates. The majority of the output of the public utility Debtors in the United States is sold at market prices pursuant to these authorizations, although certain of the Debtors' facilities sell their output under cost-based RMR agreements, as explained below. FERC may revoke or limit a Debtor's market-based

rate authority if it determines that the Debtor possesses market power. FERC requires that Debtors with market-based rate authority, as well as those with blanket certificate authorization permitting market-based sales of natural gas, adhere to certain market behavior rules and codes of conduct, respectively. If a Debtor violates the market behavior rules or codes of conduct, FERC may require a disgorgement of profits, revoke the Debtor's market-based rate authority or blanket certificate authority or impose monetary penalties. If FERC were to revoke a Debtor's market-based rate authority, the Debtor would have to file and have FERC accept a cost-based rate schedule for all or some of its sales of electricity at wholesale. If FERC revoked the blanket certificate authority of a Debtor, it would no longer be able to make certain sales of natural gas.

In an effort to promote greater competition in wholesale electricity markets, FERC has encouraged the formation of ISOs and RTOs. In those areas where ISOs or RTOs control the regional transmission systems, market participants have expanded access to transmission service. ISOs and RTOs also may operate real-time and day-ahead energy and ancillary services markets, which are governed by FERC-approved tariffs and market rules. Some RTOs and ISOs also operate capacity markets. Changes to the applicable tariffs and market rules may be requested by market participants, state regulatory agencies and the system operator, and such proposed changes, if approved by FERC, could have an impact on the Debtors' operations and business plan. While participation by transmission-owning public utilities in ISOs and RTOs has been and is expected to continue to be voluntary, the majority of such public utilities in New England, New York, the Mid-Atlantic, the Midwest and California have joined the existing ISO/RTO for their respective region. The majority of Debtors' facilities operate in these ISO/RTO regions.

The Debtors are not currently subject to the PUHCA and do not anticipate becoming so. They would become subject to PUHCA if, for example, they acquired the securities of a public utility company or a public utility facility that does not qualify as an exempt wholesale generator, a foreign utility company, or a qualifying small power production or cogeneration facility. Currently, however, all of the Debtors and their subsidiaries owning generation in the United States are exempt wholesale generators under PUHCA and all of the Debtors' subsidiaries owning generation outside the United States are either foreign utility companies or exempt wholesale generators. PUHCA will be repealed in early 2006 by the Energy Policy Act of 2005.

At the state and local levels, regulatory authorities have historically overseen the distribution and sale of retail electricity to the ultimate end user, as well as the siting, permitting, and construction of generating and transmission facilities. The Debtors' existing generation may be subject to a variety of state and local regulations, including regulations regarding the environment, health and safety, maintenance, and expansion of generation facilities. The Debtors that sell at the retail level in states that have a retail access program may be subject to state certification requirements and to bidding rules to provide default service to customers who choose to remain with their regulated utility distribution companies.

(A) Mid-Atlantic

The Debtors' Mid-Atlantic facilities sell power into the markets operated by PJM, which FERC approved to operate as an ISO in 1997 and as an RTO in 2002. The Debtors have access to the PJM transmission system pursuant to PJM's Open Access Transmission Tariff. PJM operates the PJM Interchange Energy Market, which is the region's spot market for wholesale electricity, provides ancillary services for its transmission customers, and performs transmission planning for the region. To account for transmission congestion and losses, PJM calculates electricity prices using a locational marginal pricing model and dispatches electricity on a security constrained least cost basis. On January 24, 2005, FERC issued an order changing PJM's mitigation rules for frequently mitigated units (those mitigated in excess of 80% of annual running hours), as well as the retirement policy rules. The revised policy provides some opportunity for increased compensation for frequently mitigated units. Under the old rules, such units were restricted to bidding variable costs plus 10% when a transmission constraint caused the unit to be selected out of economic merit order. Under the new rules, the restriction is variable costs plus $40 per MWh. Generally, units mitigated less than 80% of the time remain under the old "cost plus 10%" policy. However, certain units deemed "sister" units, including certain Mirant units, are permitted to bid in accordance with the new rules. PJM also proposed a revised generation retirement policy that sets forth a process by which PJM will address a request by a generation owner to deactivate a unit, determine whether established reliability criteria would

be violated if the unit were deactivated, and provide compensation to the generation owner when a unit proposed for deactivation is required to continue operating for reliability. This proposal was also approved. Both changes are currently effective, although possibly subject to revision via requests for rehearing. On August 31, 2005, PJM filed its Reliability Pricing Model ("RPM") at FERC. This proposal is intended to improve and expand upon its current Installed Capacity rules. If ultimately approved by FERC in a form not materially different from what was filed, the RPM would result in increased opportunities for generators to receive an incremental revenue stream for their capacity. However, the likelihood and timing of approval are unknown, and the specific benefit, if any, to the Debtors' business activities cannot reliably be estimated at this time.

PJM has greatly expanded its system over the last two years with the addition of the service areas of Allegheny Power, Commonwealth Edison, AEP-East, Duquesne Light, Dayton Power & Light ("DP&L") and Dominion-Virginia Power. In the fall of 2004, PJM completed its integration of AEP and DP&L into the PJM RTO. For purposes of determining deliverability to the unforced capacity market ("UCAP Market"), AEP and DP&L were deemed to be capable of providing capacity to all areas of PJM. This effectively provided the same comparability of delivery for a generator in western Ohio to deliver capacity to the Pepco zone where the Debtors' Assets are located. The deliverability standard and the additional capacity that the new entrants are now capable of providing to the UCAP Market in PJM has severely depressed forward pricing for capacity. PJM's RPM proposal, if accepted by FERC as proposed, will phase in locational deliverability zones over a several year period.

In addition, PJM and MISO have been directed by FERC to establish a common and seamless market, an effort that is largely dependent upon MISO's ability to first establish and operate its markets.

(B) Northeast

The Debtors' New York facilities participate in a market controlled by NYISO. NYISO provides statewide transmission service under a single tariff and interfaces with neighboring market control areas. To account for transmission congestion and losses, NYISO calculates energy prices using a locational marginal pricing model that is similar to that used in the PJM and ISO-NE. NYISO also administers a spot market for energy, as well as markets for installed capacity, operating reserves, and regulation service. NYISO employs an Automated Mitigation Procedure ("AMP") in its day-ahead market that automatically caps energy bids when certain established bid screens indicate a bidder may have market power. On January 14, 2005, the United States Court of Appeals for the D.C. Circuit vacated and remanded FERC's orders approving the AMP. FERC subsequently directed the NYISO to remove the AMP procedures from its tariff for the Rest of State region, in which the Debtors' assets are located. In addition, the NYISO's locational capacity market rules use a "demand curve" mechanism to determine for every month the required amount of installed capacity as well as installed capacity prices for three locational zones: New York City, Long Island, and the rest of New York. The Debtors' facilities operate outside of New York City and Long Island. The demand curve is derived for each of the three zones by setting the price of installed capacity for 118% of peak load (peak load plus an 18% reserve margin) at the assumed price for a new generating plant to serve peak demand ("new entrant") and then sloping the "demand curve" for installed capacity downward to reflect additional amounts of capacity beyond the 118%. FERC approved the new entrant price for use from the summer of 2003 to the spring of 2005 and required NYISO to file three proposed new entrant prices that would be applicable from the summer of 2005 through the spring of 2008. On January 7, 2005, NYISO filed revisions to its services tariff to define the demand curves for capability years 2005/2006, 2006/2007 and 2007/2008. On April 21, 2005, FERC issued an order accepting the NYISO's demand curves for the next three years with minor modifications to what was proposed. FERC's 2003 order approving the existing demand curves was upheld by the United States Court of Appeals for the District of Columbia Circuit. On July 27, 2005, the New York Public Service Commission ("NYPSC") instituted a proceeding to develop policies and procedures regarding retirement of generation units operated by exempt wholesale generators ("EWGs"), which would include the Debtors' New York facilities. The Debtors do not know at this point what rules will be promulgated by the NYPSC; however, there is a risk that rules interfering with the Debtors' ability to make unfettered business decisions regarding unit retirements could be implemented. Such regulations could have a material adverse impact on the Debtors' business activities in the State of New York.

The Debtors' New England plants also participate in a market administered by ISO-NE, under contract to NEPOOL. NEPOOL is a voluntary association of electric utilities and other market participants in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. FERC has approved an RTO for the New England region, which assumed responsibility for the operation of transmission systems and administration and settlement of the wholesale electric energy, capacity and ancillary services markets on February 1, 2005. ISO-NE utilizes a locational marginal pricing model, with a price mitigation method similar to NYISO's AMP. In 2004, FERC approved a locational installed capacity market ("LICAP") for ISO-NE based on the "demand curve" concept also used by NYISO. A hearing on the demand curve parameters was held in late February and early March. An initial decision was issued by a FERC administrative law judge on June 15, 2005. FERC subsequently issued an order delaying the effective date of LICAP until at least October 2006. Oral arguments have been scheduled on the merits of LICAP and the initial decision on September 20, 2005. Due to political pressure from elected officials and other policymakers in New England opposing LICAP, the Debtors cannot predict if or when it may be implemented.

(C) Mid-Continent

The Debtors' Mid-Continent facilities are located in the Midwest and Southeast markets. In the Midwest markets, the Debtors' facilities participate in a market administered by MISO. MISO uses locational marginal pricing for energy and associated financial transmission rights, so that market participants may manage the risks associated with moving energy from generation sources to load. Currently, MISO is evaluating resource adequacy issues. As a result of that process, it may or may not choose to implement a mandatory capacity purchase requirement (capacity market). If it does so, the precise implementation date is unknown, but it will be in 2007 at the earliest. MISO also is expected to implement mitigation rules similar to those of the NYISO, but without the "automated" price cap feature. The Debtors' Sugar Creek facility is interconnected to both MISO and PJM, through Cinergy and AEP's transmission system, and can sell into either market (although not into both simultaneously). Sugar Creek is eligible to participate in the PJM capacity and energy markets.

In the Southeast, the Debtors currently sell electric energy and capacity from their facilities under bilateral contracts that contain terms and conditions that are not standardized and that have been negotiated on an individual basis. Customers in this region include investor-owned, vertically integrated utilities, municipalities, and electric cooperatives.

(D) West

The Debtors' West region facilities are located in the Western Interconnection and the ERCOT market in Texas. California accounts for roughly 40% of the energy consumption in the Western Interconnection. Approximately 75% of California's demand is served from facilities in the CAISO control area, which includes the California facilities of the Debtors. The CAISO schedules transmission transactions, arranges for necessary ancillary services, and administers a real-time balancing energy market. The CAISO has proposed changes to its market design to more closely mirror the eastern RTO markets. The market redesign has been delayed several times, with full implementation now expected in 2007 or 2008. The CPUC has taken the lead role for establishing capacity requirements in California and has ordered California's load-serving entities to meet specific load and reserve requirements beginning in the summer of 2006. The CAISO has not proposed a capacity market mechanism in its market redesign.

The majority of the Debtors' Assets in California are subject to RMR agreements with the CAISO. These agreements require certain of the Debtors' facilities, under certain conditions and at the CAISO's request, to operate at specified levels in order to support grid reliability. Under these RMR agreements, the Debtors recover, through fixed charges, either a portion ("RMR Contract Condition 1") or all ("RMR Contract Condition 2") of the annual fixed revenue requirement of the generation assets as approved by FERC (the "Annual Requirement"). The Debtors' California generation assets operating under RMR Contract Condition 1 depend on revenue from sales of the output of the plants at market prices to recover the portion of the plant's fixed costs not recovered in RMR payments. For these generation assets, only a percentage of the Annual Requirement, as approved by FERC, can be recovered through RMR payments, whereas RMR Contract Condition 2 Units recover 100%. As part of the California Settlement, the Debtors owning the facilities subject to the RMR agreements entered into two power purchase agreements with PG&E

that allow PG&E to dispatch and purchase the power output of all units of those generation assets designated by the CAISO as RMR units under the RMR agreements. The first agreement is for 2005 and the second for 2006 through 2012. Under those agreements, the units will be designated as RMR Contract Condition 1, but during 2005 through 2008, PG&E will pay the Debtors owning the facilities charges equivalent to the rates charged by those Debtors during 2004 when units were designated RMR Contract Condition 2 reduced on an aggregate basis from those 2004 rates by $5 million. After 2008, the Debtors will file annually for FERC approval of the Annual Requirement, which, once approved by FERC, will set the rates to be charged.

The CAISO imposes a $250/MWh cap on prices for energy and capacity and has implemented an AMP similar to that used by NYISO. Owners of non-hydroelectric generation in California, including certain of the Debtors' facilities, must offer power in the CAISO's spot markets if the output is not scheduled for delivery within the hour. For the remainder of the Debtors' units that are located outside of California but within the Western Interconnection, there is no single entity responsible for a centralized bid-based market for sales in the West. Outside of California, the primary markets in the West today are bilateral and adhere to the reliability standards of the Western Electricity Coordinating Council. Although the Debtors are involved in initiatives to establish new ISOs or RTOs in the West, the Debtors cannot predict when, or if, such entities will emerge, nor if market developments will have a positive or negative impact on future earnings from their Western Assets. Currently in California, FERC requires generators to keep their generation on-line and ready to offer power into the market, unless granted a waiver by the California ISO (the "must-offer requirement"). The practical effect of this rule is to obtain operating reserves without paying for them, and to dump unneeded energy into the market, thus depressing prices. On August 26, 2005, a trade association, the Independent Energy Producers, filed a complaint at FERC, requesting that it require the CAISO to implement a Reliability Compensation Services Tariff ("RCST") that would pay generators for the capacity obtained pursuant to the must-offer requirement. If granted by FERC, the new RCST is expected to result in increased capacity revenue opportunities for generators, and possibly a reduction in excess energy dumped into the market.

The Debtors' Texas plants participate in a market administered by the ERCOT ISO, which manages a major portion of the state's electric power grid. ERCOT ISO oversees competitive wholesale and retail markets resulting from electricity restructuring in Texas and protects the overall reliability of the ERCOT grid. ERCOT ISO, the only ISO that manages both wholesale and retail market operations, is regulated by the Public Utility Commission of Texas (the "PUCT"). The PUCT conducts market monitoring within ERCOT. Price mitigation measures in ERCOT include a $1,000 per MWh price cap and RMR-type contracts for congested areas. To improve congestion management, the PUCT recently established a rulemaking proceeding on wholesale market design issues that will focus on adding a congestion management mechanism based on locational pricing, similar to that used in PJM, and a day-ahead market. A revised market design is expected to be in place by 2009 but, as with other evolving market structures, the Debtors cannot provide assurance as to when the enhancements will be completed and implemented, or what the impact on the Debtors' earnings in the ERCOT market will be.

ii. Environmental Regulation

(A) Air Emissions Regulations

The business of the Debtors is subject to extensive environmental regulation by federal, state and local authorities, which requires continuous compliance with regulations and conditions established by their operating permits. The Debtors' most significant environmental requirements in the United States arise under the Clean Air Act and similar state laws. Under the Clean Air Act, the Debtors are required to comply with a broad range of requirements and restrictions concerning air emissions, operating practices and pollution control equipment. Several of the Debtors' facilities are located in or near metropolitan areas, such as New York City, Boston, San Francisco and Washington, D.C., which areas are classified by the EPA as not achieving certain national ambient air quality standards ("NAAQS"). The regulatory classification of these areas subjects the Debtors' operations in these areas to more stringent air regulation requirements, potentially including, in some cases, required emission reductions. Also, states are required by section 185 of the Clean Air Act to impose additional fees for air emissions from major sources in areas classified as severe non-

attainment for ozone and that fail to meet the attainment deadline. Although, for example, the Virginia and Maryland suburbs of Washington, D.C. are part of the Washington, D.C. non-attainment area and were classified as severe non-attainment for ozone, applying a one-hour ozone standard, the designation of the area had changed to moderate non-attainment for ozone under the now applicable eight-hour standard and the one-hour ozone standard was rescinded, effective June 15, 2005.

On September 27, 2004, the Debtors entered into a conditional consent decree resolving an enforcement proceeding with the state of Virginia and the EPA. The consent decree was also entered in to by the state of Maryland and the DOJ on behalf of the EPA. The consent decree creates annual and ozone season caps on NOx emissions, provides for certain additional pollution controls, supplemental environmental projects to be done at the Potomac River plant and a $500,000 fine. The Debtors have been engaged in further negotiations to modify the consent decree and those negotiations are not yet complete. The Debtors hope to complete those negotiations in the near future, at which time the amended consent decree would be subject to public notice and comment and submitted to the Bankruptcy Court and the district court in Alexandria.

In the future, the Debtors anticipate increased regulation of generation facilities under the Clean Air Act and applicable state laws and regulations concerning air quality. The EPA and several states in which the Debtors operate are in the process of enacting more stringent air quality regulatory requirements.

For example, the EPA promulgated regulations (the "NOx SIP Call"), which establish emissions cap and trade programs for NOx emissions from electric generating units in most of the Eastern states. These programs were implemented beginning May 2003 in the Northeast and May 2004 in the rest of the region. Under these regulations, a plant receives an allocation of NOx emission allowances. If a plant exceeds its allocated allowances, the plant must purchase additional, unused allowances from other regulated plants or reduce emissions, which could require the installation of emission controls. The Debtors' plants in Maryland, New York and Massachusetts complied with similar state and regional NOx emission cap and trade programs from 1999 to 2002, which have been superseded by the EPA NOx cap and trade program. Some of the Debtors' plants in these states are required to purchase additional NOx allowances to cover their emissions and maintain compliance. The cost of these allowances may increase in future years and may result in some of the Debtors' plants reducing NOx emissions through additional controls, the cost of which could be significant but would be offset in part by the avoided cost of purchasing NOx allowances to operate the plant.

The EPA promulgated the Clean Air Mercury Rule ("CAMR") on March 15, 2005, which utilizes a market-based cap-and-trade approach under section III of the Clean Air Act. It requires emission reductions in two phases, with the first phase going into effect in 2010 and the more stringent cap going into effect in 2018. The EPA has stated that regulation of nickel emissions from oil fired plants is not appropriate and necessary at this time. The cost to comply with such requirements could be significant.

During the course of this decade, the EPA will be implementing new, more stringent ozone and particulate matter ambient air quality standards. It also will address regional haze visibility issues, which will result in new regulations that will likely require further emission reductions from power plants, along with other emission sources such as vehicles. To implement these air quality standards, the EPA promulgated the Clean Air Interstate Rule (the "CAIR") on March 10, 2005. The CAIR establishes in the eastern United States a more stringent SO_2 cap and allowance-trading program and a year round NOx cap and allowance-trading program applicable to power plants. These cap and trade programs will be implemented in two phases, with the first phase going into effect in 2009 and more stringent caps going into effect in 2015.

The mercury regulations and the CAIR will increase compliance costs for the Debtors' operations and will likely require emission reductions from some of the Debtors' power plants, which will necessitate significant expenditures on emission controls or have other impacts on operations. The Debtors expect to incur additional compliance costs as a result of these additional requirements, which could include significant expenditures on emission controls or have other impacts on the Debtors' operations.

In addition to implementation of statutes already in existence, additional environmental requirements are under strong consideration by the federal and various state legislatures. The Bush Administration has submitted Clean Air Act multi-emission reform legislation to Congress, which would promulgate a new

emissions cap and trade program for NOx, SO_2 and mercury emissions from power plants. This legislation would require overall reductions in these pollutants from national power plant emissions of approximately 50-75% phased in during the 2008-2018 timeframe, which is similar to the types of overall reductions likely to be required under the future EPA regulations discussed above. Other more stringent multi-emission reform legislation also has been proposed in Congress by some lawmakers. There are many political challenges to the passage of multi-emission reform legislation through Congress, and it is unclear whether any of this legislation ultimately will be enacted into law.

Various states where the Debtors do business also have other air quality laws and regulations with increasingly stringent limitations and requirements that will become applicable in future years to the Debtors' plants and operations. The Debtors expect to incur additional compliance costs as a result of these additional state requirements, which could include significant expenditures on emission controls or have other impacts on the Debtors' operations.

For example, the Commonwealth of Massachusetts has finalized regulations to further reduce NOx and SO_2 emissions from certain power plants and to regulate CO_2 and mercury emissions for the first time. Mercury emission reductions will be required exclusively from coal-fired facilities. These regulations, which become effective in the 2005-2008 timeframe, will apply to the Debtors' oil fired Canal plant in the state, will increase the Debtors' operating costs and will likely necessitate the installation of additional emission control technology.

Another example is in the San Francisco Bay area, where the Debtors own power plants. NOx emission standards have become increasingly stringent on a specified schedule over a period of several years, culminating in 2005. The Debtors will continue to apply the Debtors' NOx implementation plan for these plants, which includes the installation of emission controls as well as the gradual curtailment and phasing out of one or more of the Debtors' higher NOx emitting units.

Additionally, in 2003, the State of New York finalized air regulations that significantly reduced NOx and SO_2 emissions from power plants through a state emissions cap and allowance-trading program, which will become effective during the 2005-2008 timeframe. This regulation will necessitate that the Debtors act on one, or a combination, of the following options: (1) install emission controls at some of the Debtors' units to reduce emissions, (2) purchase additional state NOx and SO_2 allowances under the regulatory program, or (3) reduce the number of hours that units operate. The Debtors expect to incur additional compliance costs as a result of these additional state requirements, which could include significant expenditures on emission controls or have other impacts on the Debtors' operations.

Nine Northeast and Mid-Atlantic states have created a cooperative to discuss the design of a regional cap and trade program initially covering carbon dioxide emissions from power plants in the region, called the "Regional Greenhouse Gas Initiative" (the "RGGI"). In the future, the RGGI may be extended to include other sources of greenhouse gas emissions and greenhouse gases other than carbon dioxide. Along with the nine primary states, Maryland and Pennsylvania are observing the process and potential impacts.

These examples are illustrative but not a complete discussion of the additional federal and state air quality laws and regulations which the Debtors expect to become applicable to the Debtors' plants and operations in the coming years. The Debtors will continue to evaluate these requirements and develop compliance plans that ensure the Debtors appropriately manage the costs and impacts.

(B) Other Environmental Regulations

There are other environmental laws in the United States, in addition to air quality laws, that also affect the Debtors' operations. The Debtors are required under the Clean Water Act to comply with effluent and intake requirements, technological controls and operating practices. The Debtors' wastewater discharges are permitted under the Clean Water Act, and the Debtors' permits under the Clean Water Act are subject to review every five years. As with air quality regulations, federal and state water regulations are expected to increase and impose additional and more stringent requirements or limitations in the future. For example, in 2004, the EPA issued a new rule that imposes more stringent standards on the cooling water intakes for power plants. The Debtors expect to incur additional costs to comply with this new rule.

The Debtors' facilities also are subject to several waste management laws and regulations in the United States. The Resource Conservation and Recycling Act of 1976 sets forth very comprehensive requirements for handling of solid and hazardous wastes. The generation of electricity produces non-hazardous and hazardous materials, and the Debtors incur substantial costs to store and dispose of waste materials from the Debtors' facilities. The EPA may develop new regulations that impose additional requirements on facilities that store or dispose of fossil fuel combustion materials, including types of coal ash. If so, the Debtors may be required to change the Debtors' current waste management practices at some facilities and incur additional costs for increased waste management requirements.

Additionally, the Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, commonly known as the "Superfund Act", establishes a framework for dealing with the cleanup of contaminated sites. Many states have enacted state superfund statutes. Some of the landfills that are used for the disposal of ash may be subject to these regulations.

(C) Current Enforcement Issues

In 1999, the DOJ on behalf of the EPA commenced an enforcement action against the power generation industry for alleged violations of the NSRR promulgated under the Clean Air Act, which require permitting and other requirements for maintenance, repairs and replacement work on plants. This action ultimately came to encompass the vast majority of coal fired plants, with litigation against many of the largest utilities. These enforcement actions concern maintenance, repair and replacement work ("MRR Work") at power plants that the EPA alleges violated permitting and other requirements under the NSRR, which, among other things, could require the installation of emission controls at a significant cost. As a general proposition, the power generation industry disagrees with the EPA's positions in the lawsuits and contends that this work was "routine" and exempt from the permit requirement. In 2003, there were two trial court decisions that most directly addressed the issue of whether certain MRR Work triggers permitting and other NSRR requirements. The courts are split on the issue.

To date, no lawsuits or administrative actions alleging similar NSRR violations have been brought by the EPA against the Debtors or any of the Debtors' power plants. However, in 2001 the EPA requested information concerning some of the Mid-Atlantic plants covering a time period that predates the Debtors' ownership and leases.

In addition, there were two regulatory developments concerning NSRR in 2003 that will affect the EPA's future application of NSRR and potentially NSRR enforcement actions. In a new NSRR rule, the EPA promulgated an exemption from NSRR for MRR Work that does not exceed 20% of the replacement value of a unit, which is generally consistent with power plant MRR Work practices. In the rulemaking, the EPA also announced a policy of interpreting NSRR in a way that seems generally consistent with reasonable industry practices. The new rule is being challenged in federal court and has been stayed pending judicial review. On July 1, 2004, the EPA granted reconsideration of the rule and sought public comment. On June 6, 2005, after evaluating the comments received during this reconsideration process, the EPA announced that it has decided not to change any aspect of the rule as it was originally issued in 2003.

In 2000, the State of New York issued a NOV to the previous owner of the Lovett facility alleging NSRR violations associated with the operation of that plant prior to its acquisition by Mirant Lovett. On June 11, 2003, Mirant New York, Mirant Lovett and the State of New York entered into a consent decree that released Mirant Lovett from all potential liability for matters addressed in the NOV previously issued by the State to the prior owner. The consent decree also released Mirant Lovett for any other potential violation of NSRR or related New York air laws prior to and through the date of entry of the consent decree by the court.

Under the decree, Mirant Lovett committed to install on Lovett's two coal-fired units by 2007 through 2008: (1) emission control technology consisting of selective catalytic reduction technology to reduce NOx emissions, (2) alkaline in-duct injection technology to reduce SO_2 emissions, and (3) a baghouse. The cost of the emission controls prescribed by the consent decree will exceed $100,000,000. The consent decree allows Mirant Lovett to shut down or convert one of the units to burning natural gas only rather than install the prescribed emission controls on the unit. For one of the units, Mirant Lovett also has the option to convert the

unit to operate exclusively as a gas fired boiler and limit the hours of operation rather than install the prescribed emission controls.

2. The International Business

Through various subsidiaries, Mirant owns or controls, under operating agreements, various generation, transmission and distribution operations in the Philippines and the Caribbean. None of these international subsidiaries are in bankruptcy. The following international interests or properties were owned or leased as of March 1, 2005:

Power Generation Business	Location	Plant Type	Primary Fuel	Mirant's % Leasehold/ Ownership Interest	Total MW (Net)	Net Equity Interest/ Lease in Total MW
Philippines:						
Sual	Sual, Pangasinan	Baseload	Coal	94.9	1,218	1,155
Pagbilao	Pagbilao, Quezon	Baseload	Coal	95.7	735	704
Navotas II[a]	Manila	Standby	Diesel	100	95	95
Mindoro	Pinamalayan, Oriental Mindoro	Peaking/Intermediate/ Baseload	Heavy Fuel Oil	50	6	3
Ilijan	Batangas	Baseload	Natural Gas	20	1,200	240
Nabas[b]	Nabas, Aklan	Baseload	Oil	50	11	6
New Washington[b]	New Washington, Aklan	Baseload	Oil	50	5	2
Sangi	Toledo, Cebu	Baseload/Peaking/ Standby	Coal/Oil	50	75	38
Carmen	Toledo, Cebu	Peaking/Standby	Heavy Fuel Oil	50	37	19
Panay	Iloilo City, Panay	Peaking/Intermediate/ Baseload	Oil	50	71	35
Avon River	Iloilo City, Panay	Peaking/Intermediate/ Baseload	Oil	50	18	9
Subtotal					3,471	2,306
Caribbean:						
Grand Bahama Power	Bahamas	Peaking/Intermediate/ Baseload	Oil	55.4	133	74
PowerGen	Trinidad & Tobago	Intermediate/Peaking/ Baseload	Natural Gas	39	1,157	451
JPS	Jamaica	Intermediate/Baseload/ Peaking	Oil/Hydro	80	600	480
CUC	Netherlands Antilles	Baseload/Peaking	Pitch/Refinery Gas	25.5	133	34
Subtotal					2,023	1,039
International Total					5,494	3,345

[a] The Navotas II facility was transferred to NPC on August 1, 2005.

[b] The Nabas and New Washington facilities are scheduled to become operational in late 2005. The actual net MWs for these facilities will be adjusted after plant start-up.

a. Philippines

i. Overview

Currently, Mirant, indirectly through its Philippine subsidiaries, has ownership, leasehold or similar interests in ten generating facilities in the Philippines. As of March 1, 2005, the net ownership interest of Mirant in the generating capacity of these facilities was approximately 2,300 MW. Over 80% of the generation

capacity of the Philippines facilities is sold under long-term energy conversion agreements with the NPC. NPC acts as both the fuel supplier and the energy off-taker under the energy conversion agreements for the Pagbilao, Sual, Navotas II and Ilijan facilities. NPC procures all of the fuel necessary for generation under an energy conversion agreement, at no cost to the respective subsidiary or associate, and has substantially all fuel risks and fuel related obligations other than those relating to the fuel burning efficiency of the facility. In addition to the energy conversion agreements with NPC, the respective Sual and Pagbilao subsidiaries have joint marketing agreements with NPC for excess capacity of 218 MW and 35 MW, respectively. Currently, electricity from the excess capacity of the Sual facility is provided to select markets such as economic zones, industries and private electric distribution companies and cooperatives.

Under the energy conversion agreements, the respective subsidiaries receive both fixed capacity fees and variable energy fees. Currently, approximately 90% of the revenues with respect to Mirant's Philippine operations come from fixed capacity charges under long-term contracts that are paid without regard to the dispatch level of the facility. Nearly all of the capacity fees are denominated in U.S. dollars. Energy fees have both U.S. dollar and Philippine peso components that are indexed to inflation. The majority of the obligations of NPC under the energy conversion agreements are guaranteed by the full faith and credit of the Philippine government. The energy conversion agreements are executed under the Philippine government's build-operate-transfer program. At the end of the term of each energy conversion agreement, the facility is to be transferred to NPC, free from any lien or payment of compensation. The energy conversion agreement for the Navotas II facility expired on July 31, 2005 and the facility was transferred to NPC on August 1, 2005. The energy conversion agreements for the Sual, Pagbilao and Ilijan facilities expire in October 2024, August 2025 and January 2022, respectively.

The larger of the projects in the Philippines have been granted preferred or pioneer status that, among other things, has qualified them for income tax holiday incentives of three to six years. The income tax holiday incentive expired in June 2002 for the Pagbilao facility and will expire in October 2005 and January 2008 for the Sual facility and Ilijan facility, respectively.

As part of its revenue enhancement program, the Philippine government has enacted certain changes to its existing tax law. The new law retains the value added tax ("VAT") at 10% but lifts current exemptions of power and petroleum companies from the VAT. The law also gives the President of the Philippines the authority to increase the VAT to 12% under certain conditions beginning January 1, 2006. Furthermore, the law raises the corporate tax rate from its current level of 32% to 35% up to December 31, 2008 and reduces it to 30% effective January 1, 2009.

On September 1, 2005, the Court issued a decision upholding the constitutionality of the new VAT law. The Court, however, said that the government cannot implement the law until the temporary restraining order it issued on July 1, 2005 is lifted upon the decision's becoming final.

In addition, the Congress of the Philippines convened its regular legislative session on July 25, 2005. The Senate Committee on Energy may continue hearings concerning the effects of independent power producers, including Mirant Philippines, on the financial condition of the NPC. If such hearings were to occur, their outcome and effect on Mirant's contracts with the NPC cannot now be determined.

Mirant Philippines' energy conversion agreements with the NPC provide "change in law protection" and the Republic of the Philippines has issued performance undertakings to guarantee performance of the NPC's obligations under its energy conversion agreements. While Mirant believes that it maintains adequate contractual rights and governmental assurances to prevent any adverse financial impact to operations resulting from the new tax law, its ultimate effect cannot be determined at this time.

ii. Deregulation and Privatization

In June 2001, the Philippine Congress approved and passed into law the Electric Power Industry Reform Act ("EPIRA"), providing the mandate and the framework to introduce competition in the Philippine electricity market. EPIRA also provides for the privatization of the assets of NPC, including its generation and transmission assets, as well as its contracts with independent power producers ("IPPs"). The deregulation

of the Philippine electricity industry and the privatization of NPC have been long anticipated, and EPIRA is not expected to have a material impact on the existing Philippine assets and operations of Mirant.

EPIRA provides that competition in the retail supply of electricity and open access to the transmission and distribution systems would occur within three years from its effective date. Prior to June 2002, concerned government agencies were to establish a wholesale electricity spot market, ensure the unbundling of transmission and distribution wheeling rates and remove existing cross-subsidies provided by industrial and commercial users to residential customers. As of December 2004, most of these changes have started but are considerably behind the schedule set by the Philippine Department of Energy.

Under EPIRA, NPC's generation assets are to be sold through transparent, competitive public bidding, while all transmission assets are to be transferred to the Transmission Company, initially a government-owned entity that is to eventually be privatized. The privatization of these NPC assets has been delayed and is considerably behind the schedule set by the Philippine Department of Energy.

EPIRA also created the Power Sector Assets and Liabilities Management Corporation ("PSALM"), which is to accept transfers of all assets and assume all outstanding obligations of NPC, including its obligations to IPPs. One of PSALM's responsibilities is to manage these contracts with IPPs after NPC's privatization. PSALM also is responsible for privatizing at least 70% of all the transferred generating assets and IPP contracts no later than three years from the effective date of the law. As of December 2004, the work related to the planned privatization has commenced but is considerably behind schedule.

Consistent with the announced policy of the Philippine government, EPIRA contemplates continued payments of NPC's obligations under its energy conversion agreements. The energy conversion agreements of Mirant's Philippine subsidiaries are not assignable without consent. Mirant Philippines is in continuing discussions with NPC and PSALM on a proposal to add PSALM as an additional obligor under its existing IPP contracts. Additionally, the Philippines issued performance undertakings to guarantee the performance of NPC's obligations under the energy conversion agreements.

iii. Philippines IPP Contract Review

Pursuant to EPIRA, a governmental inter-agency committee reviewed all IPP contracts and reported that some contracts had legal or financial issues requiring further review or action, including contracts with Mirant subsidiaries. Subsequently, Mirant Philippines, NPC, PSALM, the Department of Energy and the Department of Justice entered into a letter of agreement establishing a general framework (the "General Framework Agreement") for resolving all outstanding issues raised by the committee about IPP contracts with Mirant subsidiaries.

In March 2003, the conditions precedent for the Sual and the Pagbilao components of the General Framework Agreement were satisfied and the implementation agreements relating to both became effective. As a result of the General Framework Agreement, the original energy conversion agreements for the Sual and the Pagbilao facilities remain intact and are reaffirmed with no resultant material financial impact.

b. Caribbean

i. Grand Bahama Power

Mirant owns a 55.4% interest in Grand Bahama Power, an integrated electric utility company that generates, transmits, distributes and sells electricity on Grand Bahama Island. Grand Bahama Power has the exclusive right and obligation to supply electric power to the residential, commercial and industrial customers on Grand Bahama Island. Grand Bahama Power's rates are approved by the Grand Bahama Port Authority.

ii. PowerGen

Mirant owns a 39% interest in PowerGen, a power generation company that owns and operates three plants located on the island of Trinidad. The electricity produced by PowerGen is provided to the T&TEC, the state-owned transmission and distribution monopoly, which serves approximately 347,000 customers on the islands of Trinidad and Tobago and holds a 51% interest in PowerGen. PowerGen has a power purchase agreement for approximately 820 MW of capacity and spinning reserve with the T&TEC, which expires in

2009 and is guaranteed by the government of Trinidad and Tobago. Under this contract, the fuel is provided by the T&TEC.

In response to a September 3, 2004 request for proposals issued by National Gas Company of Trinidad and Tobago Limited ("NGC"), on November 30, 2004, PowerGen submitted a bid to build new generation and provide electric generation capacity under a long-term power purchase agreement to National Energy Corporation ("NEC") and T&TEC. The request for proposals contemplates a need for between 200 MW and 250 MW for T&TEC and possibly a further need of between 400 MW and 540 MW for NEC with commercial operations dates between the third quarter of 2006 and March 2008. PowerGen will likely have a definitive resolution to this bid by year end 2005. The capital expenditures, revenues and costs associated with this potential new generation project are not included in the Projections.

iii. JPS

Mirant owns an 80% interest in JPS, a fully integrated electric utility company that generates, transmits, distributes and sells electricity on the island of Jamaica. JPS operates under a 20-year All-Island Electric License that expires in 2021 and provides JPS with the exclusive right to sell power in Jamaica. JPS has net installed generation capacity of 600 MW, and it purchases an additional 146 MW of firm capacity from three IPPs under long-term purchase agreements and additional energy from a 20 MW wind farm on an as-available basis. JPS supplies electric power to approximately 540,000 residential, commercial and industrial customers in Jamaica. JPS is regulated by the Office of Utilities and Regulation under a price cap model with rate cases held every five years and with interim adjustments indexed to inflation, foreign exchange and fuel movements.

iv. CUC

Mirant owns a 25.5% interest in CUC at the Isla Refinery in Curacao, Netherlands Antilles. The 133 MW facility provides electricity, steam, desalinated water and compressed air to the refinery, and up to 45 MW of electricity to the Curacao national grid.

v. Aqualectra

Mirant owns a $40,000,000 convertible preferred equity interest in Aqualectra, an integrated water and electric company in Curacao, Netherlands Antilles, which is owned and operated by the government. Aqualectra has electric generating capacity of 235 MW and drinking water production capability of 69,000 cubic meters per day. Aqualectra serves approximately 65,000 electricity and water customers. Mirant receives 16.75% preferred dividends on its $40,000,000 investment on a quarterly basis. Aqualectra has a call option and Mirant has a put option, both of which became exercisable for the three-year period beginning December 19, 2004. Mirant also has an option to convert its convertible preferred equity interest in Aqualectra to common shares during the same three-year period.

c. Environmental Regulation

Some of the international operations of Mirant are subject to comprehensive environmental regulation similar to that in the United States and these regulations are expected to become more stringent in the future. Additionally, other countries in which subsidiaries of the Debtors have operations, such as Trinidad and Tobago and Jamaica, are developing increased environmental regulation of many industrial activities, including increased regulation of air quality, water quality, noise and solid waste management.

Over the past several years, federal, state and foreign governments and international organizations have debated the issue of global climate change and policies regarding the regulation of greenhouse gases ("GHGs"), one of which is CO_2 emitted from the combustion of fossil fuels by sources such as vehicles and power plants. Recently, the European Union and certain developed countries ratified the Kyoto Protocol, an international treaty regulating GHGs, and it became effective on February 16, 2005. The current U.S. administration is opposed to the treaty and the United States has not ratified, and is not expected to ratify, the treaty. Therefore, the treaty does not bind the United States. None of the countries in which the Debtors or their subsidiaries presently own or operate power plants has any binding obligations under the treaty. The Commonwealth of Massachusetts has promulgated CO_2 emission standards for certain power

plants, as discussed above in "General Information — The North American Business — Regulatory Environment — Environmental Regulation — Air Emissions Regulation".

B. Employees

At December 31, 2004, Mirant's corporate offices and majority-owned or controlled subsidiaries employed approximately 4,700 persons. This number includes approximately 550 employees in the corporate and North America headquarters in Atlanta, approximately 1,350 employees at operating facilities in the United States and approximately 2,800 international employees. Substantially all of the Debtors' U.S. employees are employed centrally at Mirant Services.

Approximately 900 of the domestic employees are subject to collective bargaining agreements with one of the following unions: the International Brotherhood of Electrical Workers, the Utilities Workers of America or the United Steel Workers.

Approximately 1,800 employees in international business units belong to unions. These unions include: in Jamaica, the Jamaica Public Service Managers' Association, the Union of Clerical, Administrative and Supervisory Employees, the National Workers' Union and the Bustamante Industrial Trade Union; in Grand Bahama, the Bahamas Industrial Engineers, Managerial and Supervisory Union and the Commonwealth Electrical Workers Union; in Trinidad, the Oilfield Workers' Trade Union and Senior Staff Association; and in Curacao, the Petroleum Workers' Federation of Curacao.

Mirant provides compensation and benefits consistent with competitive practices, enabling the attraction, retention, and motivation of qualified employees. Mirant's compensation philosophy endeavors to create linkage between pay and the achievement of strategic, financial, and individual goals, as well as the creation of long-term value.

C. Existing Financing Transactions of the Debtors

1. Mirant

a. Mirant Credit Facilities

Prior to the Petition Date, Mirant maintained three corporate credit facilities. The facilities included: (i) a \$1,125,000,000 364-day senior unsecured revolving credit facility for general corporate purposes, that was converted into a term loan facility that matured in July 2003 (the "Mirant 364-Day Revolver"), (ii) a \$1,125,000,000 four-year senior unsecured revolving credit facility for general corporate purposes, that was to mature in July 2005 (the "Mirant 4-Year Revolver"), and (iii) a \$450,000,000 five-year senior unsecured revolving credit facility for general corporate purposes, that matured in April 2004 (the "Mirant "C" Facility").

b. Mirant Debt Securities

As set forth on the Schedules, Mirant issued the following senior unsecured debt securities: (i) \$200,000,000 of 7.4% Senior Notes due 2004, (ii) \$500,000,000 of 7.9% Senior Notes due 2009, (iii) \$750,000,000 of 2.5% Convertible Senior Debentures due June 2021, but subject to put options in June of 2004, 2006, 2011 and 2016, and (iv) \$370,000,000 of 5.75% Convertible Senior Notes due July 2007 (collectively, the "Mirant Notes"). In addition, Mirant Corporation issued \$356,000,000 of 6¼% Junior Convertible Subordinated Debentures, Series A due 2030 (the "Subordinated Notes"), to Mirant Trust I. The Subordinated Notes are unsecured obligations of Mirant that are junior to Mirant's senior debt, which includes the Mirant Notes, the Mirant 364-Day Revolver, the Mirant 4-Year Revolver and the Mirant "C" Facility.

c. Mirant Trust I Convertible Trust Preferred Securities

Mirant Trust I, a Delaware business trust, issued \$345,000,000 of 6¼% Convertible Trust Preferred Securities, Series A (the "Trust Preferred Securities"), the proceeds of which were used to purchase the Subordinated Notes. The Trust Preferred Securities had substantially the same financial terms as the Subordinated Notes. The Trust Preferred Securities contain the right of the holder to convert the Trust Preferred Securities into common stock of Mirant at any time after October 2, 2001 at a conversion rate equal

to a conversion price of $27.50 per share. Because these Trust Preferred Securities are not direct obligations of Mirant, they are not addressed specifically as part of the Plan. As discussed above, Mirant Trust I has agreed that the Subordinated Notes, the principal and interest on which are pledged to the payment of the Trust Preferred Securities, are subordinated to certain senior indebtedness of Mirant, including indebtedness under certain credit facilities and debt securities of Mirant. In the absence of a settlement and compromise, the Subordinated Notes and consequently the Trust Preferred Securities, would be contractually entitled to retain its recovery only if such contractually senior indebtedness is paid in full.

2. MAEM

As of the Petition Date, MAEM was party to the Commodity Prepay Facility with Scarlett Resource Merchants, LLC and HVB Risk Management. Pursuant to the Commodity Prepay Facility, MAEM received $217,000,000, which was the discounted present value of the notional value of future deliveries of natural gas (10% of such deliveries were scheduled for each of October 2002 and October 2003, and 80% for October 2004). The Commodity Prepay Facility had a 15% collar on the notional natural gas price and was to settle financially. The Commodity Prepay Facility also included a swap transaction with HVB Risk Management as the fixed price payor at the same prices and amounts as the forward sale. Mirant guaranteed the obligations of MAEM under the Commodity Prepay Facility.

3. Mirant Americas Development Capital, LLC

As of the Petition Date, MADCI was party to an Equipment Warehouse Facility. The Equipment Warehouse Facility initially consisted of a $700,000,000 "true-funding" tranche and a $1,100,000,000 "treasury-backed" tranche. Pursuant to the transaction, MC Equipment Revolver Statutory Trust (the "MC Trust Lessor") was established for the purpose of owning certain gas turbines, steam turbines, heat recovery generators and other equipment (the "Turbine Facility Equipment"). The Equipment Warehouse Facility provided that, upon completion of the Turbine Facility Equipment, MADCI could purchase the Turbine Facility Equipment or the MC Trust Lessor would lease the Turbine Facility Equipment to MADCI under a master triple-net lease (the "Triple-Net Lease"). The transaction was structured to provide that the equipment would be added to the Triple-Net Lease on the date of its completion and delivery, and the lease term with respect to such equipment would commence on such date and would expire seven and one half years from the closing. The lease was intended to qualify as an operating lease for MADCI.

The Equipment Warehouse Facility provided for the MC Trust Lessor to fund the acquisition of the Turbine Facility Equipment by issuing: (a) Series A1 and A2 Notes (collectively, the "A-Notes") and Series B1 and B2 Notes (collectively, the "B-Notes"), and (b) Series C1 and C2 certificates (collectively, the "Certificates") in respect of the investments in the MC Trust Lessor (in an amount equal to approximately 3% of equipment cost). The $700,000,000 "true funding" tranche was to be funded with Series A1 and B1 Notes and C1 Certificates. The $1,100,000,000 "treasury-backed" tranche was to be funded with Series A2 and B2 Notes and C2 Certificates, which were to be collateralized by a posting of collateral in an amount of 105% of amounts outstanding thereunder in the form of cash or short-term United States treasury securities acceptable to the MC Trust Lessor and the holders thereof as and when drawn. The commitment to fund the "true-funding" tranche was reduced to $500,000,000 on December 20, 2002 and further reduced to $231,000,000 on May 29, 2003. The commitment to fund the "treasury-backed" tranche was terminated on April 18, 2003. At the Petition Date, the amount outstanding under the Series A1 Notes, the Series B1 Notes and the Series C1 Certificates was $214,000,000, of which approximately $192,000,000 was recourse to Mirant pursuant to its guarantee of certain obligations of MADCI. The obligations of Mirant under the guarantee were senior unsecured obligations of Mirant.

The holders of each of the A-Notes, B-Notes and Certificates assert that the claims against MADCI are fully recourse to Mirant in their entirety.

4. West Georgia

West Georgia is party to a senior secured term loan facility which, as of the Petition Date, had a principal balance of $139,500,000. The facility had an initial maturity date of December 1, 2003 and, if not repaid at

such time, the facility was deemed refinanced and the remaining amounts were to be repaid with cash available after maintenance and operating expenses, with the final maturity date of June 1, 2009.

5. MAG

a. MAG Credit Facilities

Prior to the Petition Date, MAG maintained two corporate credit facilities: (i) a $250,000,000 senior unsecured revolving credit facility that matured in October 2004, and (ii) a $50,000,000 senior unsecured revolving credit facility that matured in October 2004.

b. MAG Debt Securities

As set forth on the Schedules, MAG issued the following senior unsecured debt securities: (i) $500,000,000 of 7.625% Senior Notes due 2006; (ii) $300,000,000 of 7.20% Senior Notes due 2008; (iii) $850,000,000 of 8.30% Senior Notes due 2011; (iv) $450,000,000 of 8.50% Senior Notes due 2021, and (v) $400,000,000 of 9.125% Senior Notes due 2031.

6. MIRMA

MIRMA is named as the "Facility Lessee" under, and as defined in, eleven separate facility lease agreements (the "MIRMA Leases"), four of which pertain to the four undivided interests created in the Dickerson Power Station and seven of which pertain to the seven undivided interests created in the Morgantown Power Station (together with the Dickerson Power Station, the "Facilities"). The eleven "Owner Lessors" under, and as defined in, the separate MIRMA Leases issued promissory notes (the "Lessor Notes") which were acquired by three "Pass Through Trusts" which raised the funds needed to acquire the Lessor Notes through sales of three series of "Pass-Through Certificates" issued by MIRMA: (a) $454,000,000 in 8.625% Series A Pass-Through Certificates; (b) $435,000,000 in 9.125% Series B Pass-Through Certificates, and (c) $335,000,000 in 10.060% Series C Pass-Through Certificates. The monies raised by the Owner Lessors in selling the Lessor Notes to the Pass Through Trusts were used to fund approximately 80% of the purchase price for the purchase from Pepco of the Facilities. The payment obligations under the MIRMA Leases ("Rent") are unsecured and exclusive obligations of MIRMA. The obligations of the Owner Lessors under the Lessor Notes are secured by the MIRMA Leases, the Rents payable by MIRMA thereunder, and certain other assets, including the Facilities. Concurrently with the execution of the MIRMA Leases, approximately 200 other agreements were executed, including a capital contribution agreement between MIRMA and Mirant dated as of December 19, 2000, (the "Capital Contribution Agreement") as to which the Owner Lessors and the trustee of the Pass Through Trusts (among others) are intended third party beneficiaries. As required under the Capital Contribution Agreement, Mirant agreed to contribute cash received from Mirant's subsidiaries, Mirant Peaker and Mirant Potomac, to MIRMA. See also "Material Claims, Litigation and Investigations — Disputed Claims with Associated Estate Causes of Action — MIRMA Leases/Litigation."

D. History of Mirant Corporation and Events Precipitating the Chapter 11 Cases

1. Formation, Initial Public Offering and Spin-Off[1]

Mirant was incorporated in Delaware on April 20, 1993 as SEI Holdings, Inc. From the date of its incorporation until September 27, 2000, Mirant was a wholly owned subsidiary of Southern. Mirant was later spun-off from Southern as an independent, publicly traded company. This transition was accomplished in two steps. First, Mirant issued approximately 20% of its stock to the public in an initial public offering on October 3, 2000 (the "IPO"). Second, Southern "spun off" the remaining 80% of Mirant's stock as a tax-free stock dividend to its shareholders on April 2, 2001 (the "Spin-Off"). At the same time that preparations were underway for the IPO and Spin-Off, Mirant was also in the process of negotiating (and implementing) a $5,050,000,000 transaction with Pepco, involving a $2,650,000,000 asset acquisition (plus approximately

[1] Pepco and SMECO requested modifications to the following section that the Debtors find objectionable. For the full text of Pepco's and SMECO's alternative language, see Exhibit E.

$2,400,000,000 in future contract performance liabilities) from Pepco. Until its delisting in July 2003, the common stock of Mirant was listed and traded on the New York Stock Exchange.

Mirant investigated potential claims and causes of action in connection with the separation of the companies, including the IPO and Spin-Off, and subsequently filed a complaint against Southern challenging certain of the transactions described herein, including the characterization of certain intercompany loans as debt, as opposed to equity. A description of this investigation and complaint is contained in "Material Claims, Litigation and Investigations — Disputed Claims With Associated Estate Causes of Action — Southern Company Investigation/Litigation." In addition, Mirant has filed a complaint against Pepco asserting that the transaction with Pepco constituted an avoidable fraudulent transfer. A description of the complaint is contained in "Material Claims, Litigation and Investigations — Disputed Claims with Associated Estate Causes of Action — Pepco Litigation."

a. Separation Agreements

In connection with the IPO and Spin-Off, Mirant and Southern entered into a number of separation agreements, including: (i) a master separation and distribution agreement; (ii) transitional services agreements (the "Transitional Service Agreements"); (iii) an indemnification and insurance matters agreement; (iv) a technology and intellectual property ownership and license agreement; (v) a confidential disclosure agreement; (vi) an employee matters agreement; (vii) a tax indemnification agreement (the "Tax Indemnification Agreement"); and (viii) agreements providing for the transfer of two Mirant subsidiaries, SE Finance Capital Corporation ("SE Finance"), a leasing subsidiary, and Southern Company Capital Funding, Inc ("Capital Funding") to Southern. The Transitional Services Agreements were with Southern Company Services, Inc. ("SCS") and various operating subsidiaries of Southern. These agreements generally provided for a fee equal to the greater of the cost (including actual direct and indirect costs) of providing the services or the market value for such services. During 2001, SCS provided primarily administrative services to Mirant at cost. During 2000, SCS and various of Southern's operating subsidiaries provided the following services to Mirant at cost: general engineering, design engineering, accounting and budgeting, business promotion and public relations, systems and procedures, training, and administrative and financial services. Such costs amounted to approximately $21,000,000 in 2000 and $4,000,000 in 2001. Included in these costs were both directly-incurred costs and allocated costs prior to Mirant's separation from Southern. The allocated costs related to SCS's corporate general and administrative overhead were approximately $7,000,000 in 2000 and less than $1,000,000 in 2001.

Until the distribution of the Mirant shares pursuant to the Spin-Off, these agreements, including the pricing of services provided to Mirant by Southern, were subject to the jurisdiction of the SEC pursuant to the provisions of PUHCA.

b. Payment of Cash Dividends to Southern Prior to the IPO

On May 24, 2000, Mirant's board of directors approved a cash dividend of $450,000,000, and on June 22, 2000, it approved an additional cash dividend of $53,000,000. Mirant's payment of the $503,000,000 in cash dividends was funded by short-term borrowing. On May 16, 2000, Mirant's board of directors approved a corporate credit facility of up to $1,250,000,000. Thereafter, Mirant entered into a revolving credit agreement with Bank of America, as agent, with commitments totaling $550,000,000. In June of 2000, this facility was syndicated among a group of lending banks and increased to $1,000,000,000, to be used for general corporate purposes. Mirant used the proceeds from the IPO and the sale of the Trust Preferred Securities by Mirant Trust I to repay $900,000,000 of short-term debt from credit lines and $581,000,000 of commercial paper. This amount included $503,000,000 of short-term debt and commercial paper obligations that were incurred to pay the May 24 and June 22 dividends to Southern. As a result of the stock offering, Southern recorded a $560,000,000 increase in paid in capital with no gain or loss being recognized.

c. Transfer of Two Mirant Subsidiaries to Southern

In conjunction with the IPO and Spin-Off, Mirant transferred SE Finance and Capital Funding, two of its subsidiaries, to Southern. The transfer was effectuated by means of a redemption of a single share of Mirant's Series B preferred stock that Mirant issued to Southern on August 30, 2000, and redeemed on

March 5, 2001, in exchange for the transfer of the subsidiaries. The issuance of the preferred share to Southern on August 30 was accounted for as a non-cash transaction at the book value of the subsidiaries, resulting in a reduction of shareholders' equity during 2000. No gain or loss to Mirant was recognized as a result of the disposition of these subsidiaries because the transfer was accounted for at book value. To implement this transaction, following the IPO and prior to the Spin-Off from Southern, Mirant formed a joint venture corporation with Southern Company Energy Solutions, Inc. ("SCES"), a wholly owned subsidiary of Southern. Mirant then contributed the stock of SE Finance and Capital Funding to this venture in return for 80% of the stock; SCES, in turn, contributed its energy services assets to a limited liability company owned by the venture in exchange for a 20% interest in the venture. In March of 2001, prior to the Spin-Off, Mirant redeemed the single share of preferred stock it had issued to Southern in exchange for Mirant's interest in the subsidiaries. Following the transfer, Southern assumed responsibility for all obligations of SE Finance and Capital Funding.

d. Capital Contributions from Southern to Mirant and Intercompany Loans

From January 1, 1997 through March 31, 2000, Mirant's financing activities provided Cash in the amount of approximately $6,346,000,000. This amount included, among other things, $3,985,000,000 of proceeds from the issuance of short-term and long-term debt (net of repayments) and $2,029,000,000 in capital contributions from Southern. In addition, prior to the IPO, Mirant periodically borrowed funds from Southern to finance acquisitions and for working capital needs. Mirant paid interest on intercompany loans based upon Southern's short-term borrowing rate. As of December 31, 1999, all amounts due from Mirant to Southern with respect to intercompany loans had been repaid, and no further sums were borrowed after that time. Accordingly, as of the IPO date, there were no intercompany loans outstanding between Southern and Mirant.

2. Financial Crisis in the U.S. Power Industry

In the summer and fall of 2000, significant volatility existed in the California wholesale electricity markets. This wholesale market volatility combined with fixed retail prices substantially impaired the ability of PG&E and Southern California Edison Company ("SCE") to meet obligations owed to many power generators, including certain of the Debtors. As a result, the Cal PX and PG&E each filed petitions for relief under chapter 11 of the Bankruptcy Code in 2001. In addition, SCE issued a moratorium on all payments to various power generators. As of September 30, 2004, MAEM had outstanding receivables for power sales made in 2000 and 2001 in California totaling between $283,000,000 and $319,900,000, although these amounts are still subject to dispute. These receivables were assigned by MAEM to PG&E, SCE and certain other California parties in 2005 as part of the California Settlement. See "The Chapter 11 Cases — California Settlement" for further details.

In addition, certain of the Debtors were named as defendants in a number of lawsuits and were the subject of a number of investigations arising out of the California utility crisis. Specifically, investigations and litigation commenced by FERC, the Attorney General of the State of California, California public utilities and various other public and private interests, beginning in late 2001: (a) questioned the efficacy of the California power markets; (b) challenged the right of energy marketers, including certain of the Debtors, to receive and hold payment for energy deliveries in 2000 and 2001, and (c) sought affirmative remedies against participants in the market, including the Debtors.

On December 2, 2001, Enron and certain of its affiliates filed petitions for relief under chapter 11 (the "Enron Bankruptcy") in the United States Bankruptcy Court for the Southern District of New York (the "Enron Bankruptcy Court"). Enron, at the time of its chapter 11 filings, was the world's largest energy trader. The collapse of Enron had the following notable implications for the Debtors. First, it eliminated liquidity in certain energy-related markets where the Debtors had actively participated. Second, the energy industry as a whole became more transparent to the capital markets, credit ratings agencies and state and federal regulators, and adversely affected the Debtors' credit capacity, liquidity and prospects.

3. Credit Rating Downgrades, Financing Issues and Accounting Issues

On December 19, 2001, Moody's Investor Services ("Moody's") unexpectedly downgraded the credit ratings of Mirant, MAG and MAEM to below investment grade. Immediately following the downgrades,

Mirant executed an "overnight" sale of 60,000,000 shares of common stock. The net proceeds were approximately $759,000,000. As a result of the Moody's downgrade, counterparties began exercising collateral and margin call rights. As a result of the increased collateral requirements, the significant indebtedness of the Debtors and the changing market conditions, including constrained access to capital, the Debtors adopted a plan to restructure their business operations in March 2002 by exiting certain activities (including the European trading and marketing business), canceling and suspending planned power plant developments, closing business development offices and severing employees. The Debtors modified the Mirant business strategy to concentrate on two principal operating segments, the North America segment, consisting of the North American generation and commodity trading operations managed as a combined business, and the international segment, consisting of a power generation business in the Philippines and power generation and integrated utility businesses in the Caribbean. The Debtors determined to focus in the following areas: (a) the development, construction, ownership and operation of power plants; (b) the ownership of electric utilities with generation transmission and distribution capabilities and electricity distribution companies; (c) the use of the risk management capabilities of the Debtors to optimize the value of their generating and gas assets and offer risk management services to others; (d) the marketing and trading of energy and energy-linked commodities, including electricity, gas, coal, oil, weather derivatives and emission allowances; and (e) the development of unique energy solutions to help customers improve their businesses. As a result of the restructuring, Mirant recorded restructuring charges in 2002 of $600,000,000 and asset impairment charges of $373,000,000 for costs relating to certain turbine purchases and development projects that were to be cancelled, sold, abandoned or placed in storage. Notwithstanding the reduced scope of the Debtors' business, the Debtors continued to have significant liquidity and capital needs as a result of ongoing collateral demands, existing equipment purchase and construction commitments, and maturing indebtedness.

During this period, the financial markets were largely unavailable to meet the liquidity and capital needs of the Debtors. Although in July 2002, Mirant successfully issued $370,000,000 of convertible senior notes for net proceeds of $361,000,000, it was unable to refinance the Mirant 364-Day Revolver in July 2002 and elected to exercise the "term-out" option to extend the facility as a term loan through July 2003. Similarly, there were other examples in 2002 of the financial markets pulling back from the energy industry and the Debtors. In January 2002, Mirant Asia-Pacific Ventures, Inc., the holding company for Mirant's Asian businesses, was able to refinance only $254,000,000 of its $792,000,000 bank facility and the balance of the repayment had to be funded by Mirant. Throughout 2002, Mirant sought but was unable to complete a construction and term financing for a portfolio of domestic generation projects. After the term-out of the Mirant 364-Day Revolver, the Debtors began evaluating how to address, either with a refinancing transaction and/or asset sales, the July 2003 maturity of the termed out revolver, as well as the April 2004 maturity of the $450,000,000 Mirant five-year senior unsecured revolving credit facility, the July 2004 maturity of $200,000,000 of Mirant Senior Notes, the potential June 2004 put of $750,000,000 of 2.5% Convertible Debentures to Mirant, and the July 2005 maturity of the Mirant 4-Year Revolver.

In July 2002, Mirant identified and disclosed several accounting errors affecting its previously issued financial statements. In connection with reviewing the accounting errors, the Audit Committee of the board of directors of Mirant engaged the law firm of King & Spalding, LLP ("King & Spalding") to conduct an independent review. The independent review by King & Spalding found no fraudulent conduct by Mirant associated with the previously disclosed accounting issues. The Debtors are unaware of any other party-in-interest that has conducted an investigation who holds a different or contrary view. During an interim review of the second quarter of 2002, Mirant's independent auditors assessed internal controls of the Debtors' North American energy marketing and risk management operations and advised the Debtors that certain deficiencies identified in that review constituted a material control weakness. As a result, in part, of the identified errors and control weakness, Mirant engaged its independent auditors to reaudit its 2000 and 2001 consolidated financial statements, which reaudit was not completed until April 2003. Ultimately, the reaudit resulted in Mirant restating, in April 2003, its 2000 and 2001 consolidated financial statements.

With the overhang of the 2003 and 2004 refinancing risk, the additional pressures posed by the reaudit and the various litigation matters and investigations then underway, the business environment in which the

Debtors operated in 2002 and early 2003 became increasingly difficult. The significant factors affecting the Debtors in 2002 and early 2003 included:

- Impairments and adjustments resulting from the combination of external factors discussed above and changes in the strategic focus of the Debtors that reduced the future estimated cash flows and adversely impacted the value of the Assets of the Debtors. In its 2002 consolidated financial statements issued in April 2003, Mirant recognized goodwill impairment charges of $697,000,000; restructuring and long-lived asset impairment charges of $973,000,000; deferred income tax valuation adjustments of $1,088,000,000; provisions for income taxes that were previously unrecognized on accumulated foreign earnings of $468,000,000; and other impairment charges of $467,000,000.

- In October 2002, Moody's downgraded the credit ratings of Mirant, MAG and MAEM even further below investment grade, and Standard & Poor's downgraded the credit ratings of these entities to below investment grade. The downgrades triggered rights of additional parties to, among other things, demand from the Debtors' collateral and margin in connection with the commodity and financial product trading activity of the Debtors and certain other key vendor and trade relationships. As a result of the increasing collateral requirements, the Debtors began scaling back the scope of their commodity trading activities, primarily physical gas.

- To reduce outstanding debt and align the business with its strategic focus, the Debtors sold certain European, Chinese and U.S. investments and operations. Net proceeds from sales of assets and minority owned investments in 2002, net of the repayment of related debt, were $1,800,000,000, including $1,100,000,000 in net proceeds from the sale of Mirant's interest in Bewag AG in February 2002.

- Limited access to capital caused Mirant to draw down its credit facilities and maintain substantially higher cash balances throughout the year, resulting in increased interest expense.

- Lower power prices and higher natural gas prices resulted in reduced "spark spreads" (the difference between the price at which electricity is sold and the cost of the fuel used to generate it) and lower gross margins in 2002, compared to high spark spreads in 2001 and 2000.

- Overall market liquidity declined. Trading volumes decreased in forward markets for both power and gas and trading volumes were projected to decline further as market participants continued to exit the trading business.

- When completed in April 2003, the reaudit of the Debtors' 2001 and 2000 consolidated financial statements resulted in a restatement of such financial statements and the audit opinion from its independent auditors included a going concern qualification.

4. Unsuccessful Out-of-Court Restructuring and Exchange Offers

Following the conversion of the Mirant 364-Day Revolver in July 2002 to a term loan, the Debtors began to evaluate alternatives to refinance their short-term and medium-term debt maturities. In October 2002, Mirant engaged Blackstone as its financial advisor to help evaluate the financial situation of the Debtors and formulate a financial restructuring plan.

On June 2, 2003, Mirant made an offer (the "Mirant Exchange Offer") pursuant to an *Offering Circular and Disclosure Statement and Solicitation of Acceptances of a Pre-packaged Plan of Reorganization,* dated June 2, 2003 (as such document was amended on June 20, 2003, further amended on June 30, 2003 and supplemented on July 9, 2003, the "Offering Circular and Disclosure Statement"). Pursuant to the Offering Circular and Disclosure Statement, Mirant offered to exchange its 7.4% Senior Notes due 2004 and its 2.5% Convertible Debentures due 2021 (collectively, the "Mirant Exchange Offer Securities') for new 8.25% Senior Secured Notes due 2008, cash and warrants to acquire the common stock of Mirant.

Concurrently therewith, MAG made an offer (the "MAG Exchange Offer" and together with the Mirant Exchange Offer, the "Exchange Offers") to certain of its creditors by way of a separate offering circular pursuant to which it offered to exchange its 7.625% Senior Notes due 2006 for new 8.25% Senior Secured Notes due 2008 and cash.

On July 14, 2003, Mirant's board of directors determined that the commencement of cases under chapter 11 of the Bankruptcy Code of Mirant and substantially all of its U.S. subsidiaries was the best way to address the Company's financial restructuring issues, maximize the value of Mirant's business enterprise and protect the assets of Mirant and its subsidiaries pending the implementation of restructuring.

VI.

CERTAIN AFFILIATE TRANSACTIONS

A. Overview

Since its formation, Mirant has operated its business through various operating subsidiaries and holding companies that carried out certain activities (e.g., trading and marketing through MAEM) or owned and operated specific Assets (i.e., the assets held by MAG and MIRMA and their respective subsidiaries). As part of the business of the Debtors, Mirant and its subsidiaries entered into a variety of intercompany relationships and transactions. The six primary types of intercompany relationships identified are:

Primary Intercompany Relationships	Major Transaction Types
Relationships with MAEM	• Fuel purchases • Power sales • Administrative services fees and margin sharing • Hedging activities

Relationships with Mirant Services and MADI	• Procurement and services activity, including:
	  • Third-party goods and services
	  • Allocation of corporate overhead
	  • Payroll and benefits

Capital Support Activity	• Guarantees/make-whole arrangements • Letters of credit
Intercompany Indebtedness	• Cash-sweep arrangement • Intercompany notes/advances
Dividend/Capital Contribution Activity	• Intercompany dividends/distributions • Capital contributions
Tax Sharing Arrangements	• Tax sharing payments

The following discussion provides an overview of certain material intercompany relationships and transactions that exist or have occurred between and among the Debtors, and a discussion of certain potential claims and remedies which may be assertable in connection with these intercompany relationships and transactions. As part of the global settlement under the Plan, all Intercompany Claims between the Debtor Groups are to be resolved and not entitled to any Plan Distribution. See "The Chapter 11 Plan — Settlement of Certain Inter-Debtor Issues — Creation of Debtor Groups." Administrative Claims between the Mirant Debtors and the MAG Debtors are to be settled in the ordinary course.

B. Material Intercompany Transactions and Relationships Among the Debtors

Although comprised of numerous separate legal entities, the Debtors have operated their business as a single integrated enterprise. As a consequence, the day-to-day operation and financing of the Debtors' business requires numerous intercompany relationships and transactions, giving rise in turn to substantial Intercompany Claims both in terms of amount and number. The Debtors utilize a centralized cash management system. In addition, certain essential functions, such as providing capital, personnel, human resources and administrative functions, and performing commercial activities (procurement of fuel, sale of energy, marketing, plant

dispatch, risk management and asset optimization activities), are performed or provided by particular Debtors for the benefit of other members of the enterprise, rather than on an entity-by-entity basis. These roles are discussed in more detail below.

1. Intercompany Relationships Involving Mirant Services

Mirant Services provides various administrative and other services to the other Debtors pursuant to a series of administrative services agreements. These services include finance, treasury, accounting, legal, procurement and human resources services. Nearly all of the Debtors' domestic personnel are employees of Mirant Services. MADI also provided some administrative services to certain Debtors under similar agreements. Mirant Services pays the state taxes of the Debtors, for which it is reimbursed.

The Debtors entered into various administrative services agreements to provide for the reimbursement of Mirant Services through the allocation of costs to the other Debtors. From January 1, 1999 to May 1, 2002, the administrative services agreements provided that the other Debtors would reimburse Mirant Services for the actual amount incurred by Mirant Services. Beginning on May 1, 2002, however, new administrative service agreements were entered into pursuant to which a new "fixed charge" allocation method was implemented. Under this system, monthly allocation amounts were calculated (based off of Mirant Services' budgeted expenses) using headcount or assets depending on the expense category. This methodology resulted in approximately 50% of costs being allocated. In January 2004, the Debtors implemented a new overhead allocation system. Under this new system, all costs on Mirant Services' books are allocated to certain other Debtors and non-Debtors.

2. Intercompany Relationships Involving MAEM

As described above in "General Information — The Businesses of Mirant — The North American Business," substantially all of the Debtors conduct their commercial activities through MAEM. In this capacity, MAEM procures fuel and sells output, manages risks, enters into hedging arrangements, and manages emissions accounts for the other Debtors. As a result, MAEM has entered into numerous intercompany transactions and agreements with the other Debtors resulting in significant Intercompany Claims and activity between MAEM and certain of the other Debtors. Of particular note are the following transactions, each of which is described in more detail below: (a) the profit sharing agreements among MAEM, Mirant Delta and Mirant Potrero; (b) the make-whole agreement; and (c) the ECSA arrangements.

a. Profit Sharing Agreements

From 1999 to 2001, MAEM and each of Mirant Delta and Mirant Potrero operated under an Energy Services Agreement and, thereafter, a Services and Risk Management Agreement. These agreements were superceded in 2002 by a Power Sale, Fuel Supply and Services Agreement, in which MAEM procured fuel for Mirant Delta and Mirant Potrero and Mirant Delta and Mirant Potrero, in turn, sold energy to MAEM. Under the first two agreements, MAEM shared in the profits of the California energy sales. For instance, Mirant Delta and Mirant Potrero paid MAEM a bonus equal to a specified bonus percentage of the amount by which net market revenues in a year exceeded a threshold amount. The bonus percentage and threshold amount were adjusted during the term of these agreements. Although MAEM has retained its share of certain profits, Mirant Delta and Mirant Potrero have not yet received payment from MAEM for energy sold in November and December of 2000 and January of 2001 because MAEM has not yet received payment from buyers in the California energy markets to which it resold the energy.

b. Make-Whole Agreement[1]

In December 2000, Mirant transferred its rights and obligations under the asset purchase agreement with Pepco with respect to PPAs to be assumed from Pepco and the TPAs to be entered into with Pepco to MAEM. This assignment resulted in MAEM incurring the rights and obligations under the TPAs and the Back-to-Back Agreement. These agreements were out-of-market, thus creating significant liabilities for

[1] Pepco and SMECO requested modifications to the following section that the Debtors find objectionable. For the full text of Pepco's and SMECO's alternative language, see Exhibit E.

MAEM. To offset this liability to MAEM, concurrently with the transfers of these TPAs and the Back-to-Back Agreement to MAEM, MAEM and Mirant entered into a make-whole agreement under which Mirant agreed to pay MAEM the difference between: (i) the market value of the energy products used by MAEM to meet the TPA and the obligations under the Back-to-Back Agreement, and (ii) the price actually received or paid by MAEM, thereby making MAEM whole. In September 2001, MAI assumed the make-whole payment obligations by entering into a make-whole agreement with MAEM after Mirant assigned its obligations to MAI.[1]

c. ECSA Arrangements

In August 2001, MAEM entered into ECSAs with Mirant Peaker, Mirant Potomac, MIRMA and Mirant Chalk Point, LLC ("Mirant Chalk Point"). The ECSAs were structured to provide favorable pricing to the generating subsidiaries and did not reflect market prices. Due to pricing determined by rates set in the ECSAs and in various hedging arrangements, there was limited exposure of the generating subsidiaries to market fluctuations. This favorable pricing was accounted for as capital contributions to the generating subsidiaries. In May 2003, the ECSAs were cancelled and replaced with Power, Sale, Fuel Supply and Services Agreements with MAEM pursuant to which energy was sold to MAEM at market prices. As a result of the termination of the ECSAs, a capital contribution receivable of approximately $82,300,000, that was previously due to MIRMA and Mirant Chalk Point as a result of the favorable pricing, was reversed on MAG's and MIRMA's books.

3. Consolidated Cash Management System

In late 2001, the Debtors implemented a centralized cash management system that provides for the collection, concentration and disbursement of funds among the Debtors. As part of this cash management system, excess cash is automatically swept into Mirant bank accounts on a daily basis. Similarly, if any Debtor requires funds, cash is transferred to such Debtor. To the extent a participating Debtor is a net supplier of funds, such amounts are generally recorded as an unsecured loan to Mirant by such Debtor and, to the extent a Debtor is a net user of funds, such amounts are generally treated as an unsecured loan to such Debtor by Mirant. However, depending on various transaction-specific factors, including any applicable commercial or legal restrictions and tax considerations, funds are also transferred between Debtors as dividends and capital contributions. During the fourth quarter of 2002, the respective subsidiaries of MAG and MIRMA were removed from the Mirant cash management system and any outstanding balances were paid and each of MAG (excluding MIRMA) and MIRMA put in place separate cash management systems with their respective subsidiaries.

4. Credit and Capital Support

Most of the Debtors did not have separate access to third-party capital and financing. Thus, historically, Mirant provided credit and capital support to affiliate Debtors, in the form of guarantees and letters of credit issued by, or pursuant to credit facilities of, Mirant, and in certain limited circumstances, certain subsidiaries of Mirant. The exposure under these guarantees and letters of credit was managed and measured under three categories: trading and marketing, asset support and other. As of June 30, 2003, the following exposures existed on guarantees issued by Mirant, MAI, MAG, MAEM and certain other subsidiaries to or for the benefit of other Mirant subsidiaries (in millions):

Guarantor	T&M	Asset	Other	Total
Mirant	$871	$207	$1,004	$2,082
MAI	—	303	171	473
MAG	—	25	—	25
MAEM	1	—	3	4
TOTAL	$872	$535	$1,178	$2,584

[1] Pepco requested modifications to this paragraph that the Debtors find objectionable. For the full text of Pepco's proposed alternative language, see Exhibit E.